Managing the structure, regulation and infrastructure investment decisions in the natural gas industry of Ghana

Shafic Suleman

Faculty of Technology
School of Engineering and Sustainable Development
Institute of Energy and Sustainable Development

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LIST OF ABBREVATIONS

AMERI – Asia Middle East Resource and Investments
BCF – Billion Cubic Feet
BG – British Gas
BOST – Bulk Oil Storage and Transportation Company Limited
CBD – Chinese Development Bank
CAPI – Carried and Participating Interest
CCGT – Combined Cycle Gas Turbine
DFO – Distillate Fuel Oil
DGSO-Domestic Gas Supply Obligation
ECA - Economic Consultancy Associates
EC – Energy Commission
EITI – Extractive Industry Transparency Initiative
FSRU – Floating Storage and Regasification Unit
FPSO – Floating Production Storage and Offloading
GNPC – Ghana National Petroleum Corporation
GNGC - Ghana National Gas Company
GTL – Gas-To-Liquids
LC – Letters of Credit
LCO – Light Crude Oil
LNG - Liquefied Natural Gas
LTD – Limited
LSHS – Low Sulphur Heavy Stock
IDA – International Development Association
IBRD – International Bank for Reconstruction and Development
ICT – Information and Communication Technology
IOC - International Oil Companies
IMF - International Monetary Fund
IPP – Independent Power Producers
IFC – International Financial Cooperation
ISSER – Institute of Statistical, Social and Economic Research
JVA – Joint Venture Agreement
KTPP – Kpong Thermal Power Plant
GDP- Gross Domestic Product
GE – General Electric
GMP - Gas Master Plan
GPP – Gas Processing Plant
GTL –Gas-to-Liquids
MBM – Multiple Buyer Model

MIGA – Multilateral Investment Guarantee Agency
MMBTU – Million British Thermal Units
MOP – Muriate of Potash
MPA – Model Petroleum Agreements
MW – Megawatts
MMBTU –Million British thermal unit
MoU – Memorandum of Understanding
MRP - Mines Reserve Plant
MT – Million Tonnes
N-Gas-Nigeria-Gas
NED – Northern Electricity Department
NGPP – Natural Gas Pricing Policy
NGTU – Natural Gas Transmission Utility
NGC – Nigeria Gas Company
NIPP – National Integrated Power Projects
NNPC – Nigeria National Petroleum Corporation
NPK – Nitrogen Phosphorus Potassium
NPA – National Petroleum Authority
kW/h – Kilowatts per hour
KM – Kilometres
OMC –Operations and Maintenance Cost
PC - Petroleum Commission
PF – Processing Fee
Plc – Public Limited Company
PIB – Petroleum Industry Bill
PURC – Public Utilities Regulatory Commission
PRMA – Petroleum Revenue Management Act
PNDC – Provisional National Defence Council
PSC/A- Production Sharing Contracts/Agreements
SBM – Single Buyer Model
SCP – Structure Conduct Performance
SGP – Sankofa Gas Project
SP – Selling Price of gas
TAPCO – Takoradi Power Company
TCA – Transaction Cost Analysis
TCF – Trillion Cubic Feet
TCE – Transaction Cost Economics
TEN – Tweneboe Enyenrar and Ntomme
TSP-Triple Super Phosphate

TT2PP – Tema Thermal 2 Power Plant
TICO – Takoradi International Power Company
TGI – Transportadora de Gas del Interior
TPA – Third Party Access
TWh – Terawatts per hour
VRA - Volta River Authority
WAGP – West African Gas Pipeline
WAGPCo - West African Gas Pipeline Company
WAGT – West African Gas Transmission
WP – Well-head price of gas

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ABSTRACT

In light of developing a nascent gas industry, present multiple challenges in restructuring, regulations and meeting infrastructure investments requirements. To identify an appropriate industry structure and provide suitable regulatory framework to attract adequate infrastructure investments are the requirement to maintain a viable nascent gas industry. The purpose of the study is to examine the conditions required for developing a viable nascent gas industry in Ghana. The study develops an analytical framework by combining the Structure-Conduct-Performance paradigm and the Transaction Cost Economics theory with stakeholder consultation in an integrated cash flow model, which identified inappropriate industry structure, ineffective regulation and high risk as challenges in the gas industry in Ghana.

The current gas industry structure and regulatory framework in Ghana is identified as state control monopoly. To strengthen the analysis of the study alternative gas industry structural models were reviewed. The Single Buyer Model (SBM) is suggested as an initial stage structure for Ghana National Petroleum Corporation (GNPC) to commercialize upstream natural gas resources and ease transactions cost. However, the SBM is constrained by the Volta River Authority (VRA) and Electricity Company of Ghana (ECG) inefficiencies. The Multiple Buyer Model (MBM) is considered as a transitional structure to solve the existing hold-up and lock-in inefficiencies of Ghana National Petroleum Corporation-Ghana National Gas Company-Volta River Authority (GNPC-GNGC-VRA) firm structure. Enforcing open access

regulations to essential infrastructure is required in the long run.

Developing an integrated gas-to-power project in Ghana is a viable business. Nevertheless, non-associated gas production from the Sankofa Gas Project is risky and requires higher gas prices and alternative downstream consumers to be viable. The Gas Processing Plant and transmission pipeline tariffs are inappropriately set and requires regulations. Providing effective regulations and governance arrangements by establishing an independent regulator through a gas sector law are important in protecting the interest of various stakeholders in the nascent gas industry in Ghana.

CHAPTER ONE
INTRODUCTION

1.0 Background

The management of the natural gas industry in the developed world (USA & UK), faces major challenges in industry restructuring, regulation and infrastructure investment decisions. These issues have been on the global policy agenda since the 1970s, and the main concerns are restructuring, re-examination of traditional incentive regulation and new understanding of risk in infrastructure investment (von Hirschhausen, 2008).

The major constraints identified from the developed world's gas sector include effects of restructuring and regulations on infrastructure investments and supply security in the UK and the US. Rapid declines in domestic gas production and increasing reliance on trans-interconnected pipelines and Liquefied Natural Gas (LNG) in the UK and problems in the implementation of the new gas sector directives (e.g. European Union directives) (von Hirschhausen, 2008; Joskow, 2005).

Additionally, the USA is becoming self-sufficient in gas production because of the shale gas boom (Wang et al., 2015). This will have impact on the global gas market (Hilaire et al., 2015) since this indicates the drying up of a major LNG importer. Besides, there is fierce global competition from coal and renewable energy (Wood, 2016). Pledges from the Paris Agreement on Climate Change in 2015 saw countries shifting to the consumption of environmentally sustainable energies. It is projected that by 2040, 60% of electricity generated will come from renewable energy (IEA, 2016).

The non-existence of a major gas importer (US), competition from renewable energies and the slow growth in global demand due to economic crisis since 2008 mean the era of the "golden age of gas" as IEA (2012) predicted has not materialised. However, fossil fuels such as oil and gas and especially gas will continue to be the bedrock of the global energy system.

While the developed countries, with their well-established gas markets, are trying to negotiate these challenges, the case of nascent gas producers of Sub-Saharan Africa is different. Ghana, Tanzania and Mozambique have found commercial quantities of gas in recent times but, unlike, their predecessors like Nigeria who have relied on gas exports to the developed countries' markets, these new entrants are seriously constrained by the loss of export market and a lack of competitiveness.

These nascent[1] gas producers (Ghana, Tanzania and Mozambique) are facing constraints in their commercialisation efforts due to lack of infrastructure, environmental concerns and lack of financing of projects (Ledesma, 2013; Fruhauf, 2014). Gas master plans which recommend government infrastructure investments, support in ownership structure, appropriate regulatory framework that gives investors security, suitable gas pricing structure with acceptable returns, non-discriminatory access to infrastructure and regulatory governance through a regulatory authority have

[1] Nascent natural gas industries require completely new gas industry development from infrastructure, regulations to structures (Fruhauf, 2014).

been developed (Ledesma, 2013; Fruhauf, 2014).

Fortunately, these countries' own economies are growing so their demand for energy is rapidly increasing. For example, Ghana is growing at 8.9% per annum (Ministry of Finance-Ghana, 2017); therefore, the power sector is unable to meet the growing electricity needs. The domestic use of gas for power generation offers an opportunity for these countries. Natural gas will be a strong "prime mover" for broad economic and social development in Africa (Ernest and Young, 2013). The use of natural gas in power generation has been a partner in energy diversification and can facilitate the transition to renewable energy development (IEA, 2012).

These opportunities, however, come with risks and challenges (Ernest &Young, 2013). The power sector remains financially weak due to government interventions and poor organisational effectiveness. In addition, as new entrants to the gas industry, infrastructure is lacking and capital intensive. Hence, will require a supportive business environment for investments. Nevertheless, such an environment is lacking due to regulatory weaknesses and weak policies.

Ghana joined the League of Nations in West Africa which discovered oil and gas resources in commercial quantities in 2007 and started producing in 2010 (Adusah-Karikari, 2015; Ablo, 2015; Cuba et al., 2014). This led to the possibility of developing a nascent gas industry. Integrated analyses of gas-to-power development in Ghana were carried-out by several agencies (Ministry of Energy-Gas Master Plan, 2015; World Bank, 2013 & 2015; Nexant, 2010) and academics (Fitsch and Poundineh, 2015; Fitsch and Poundineh, 2016) which identified gas-to-power utilisation as an economically superior strategy compared to gas export-oriented utilisation.

However, domestic gas use has remained a major problem in the region. For instance, Nigeria flares about 10% and re-injects 30% of all associated gas produced (Nwaoho and Wood, 2014; Peng and Poundineh, 2017) whilst faced with significant domestic power deficit. Lack of adequate structures and regulations have resulted in the poor development of domestic markets and inadequate infrastructure to develop these gas resources.

Developing a nascent gas industry in Ghana faces several tensions in deciding between integrated or liberalised structures, pricing and sector viability challenges, cost recovery from the power sector, inappropriate regulatory framework for investments, ineffective structural arrangements and weak institutions. Solving these require a thorough analysis of the entire supply chain.

1.1.0. The Research Knowledge Gap

The general trend in the nascent gas industry in Ghana is identifying appropriate structural and regulatory frameworks, sustaining and attracting sufficient infrastructure investments to balance demand and supply adequacies and meeting national development needs and investor interest whilst delivering low-cost energy to consumers. Adequate and reliable supply of gas is a fundamental requirement for improving power supply in Ghana (World Bank, 2013). The Ministry of Energy commissioned several studies on how Ghana can benefit from her gas resources and develop utilisation options. The Ministry, through consultants and international organisations, initiated studies to capture the ongoing thinking on gas utilization options in the country.

The Ministry of Energy initially conceived an overall gas industry development plan. Nexant (2010) set the tone for a Gas Sector Master Plan to develop a framework for the monetisation of Ghana's natural gas resources to avoid flaring. A World Bank (2013) report prioritised the power sector as the major off-taker for downstream consumption of gas and recommend providing appropriate institutional arrangements. An existing gas pricing policy by the Ministry of Energy (2012) stated the structure of the gas industry as a state-owned integrated monopoly but could not explain further.

The Economic Consultancy Associates (ECA) and Petroleum Development Consultants (PDC) developed another Gas Master Plan (GMP) (2014) which recommended gas utilisation options based on netback pricing and prioritised the power sector as the main off-taker. They recommended that a gas sector policy, regulatory framework and institutional arrangements are required for Ghana. They, as well, described the current industry structure as wholly state-owned and vertically integrated.

A recent World Bank Report (2015) on providing financial guarantees for the Sankofa Gas Project in Ghana succinctly captured the on-going thinking in the gas industry by providing comprehensive financial analysis and linking gas production to power plants for electricity generation and provided risk identification and mitigation measures.

A final Gas Master Plan (2015) developed by the Ministry of Energy encompasses all previous consultants' reports and provided an updated version of current developments in the gas industry in Ghana. A Gas Sector Act was envisaged; in it, a monopolist industry structure was identified for early stage infrastructure development and a new Natural Gas Pricing Policy (NGPP) was to be established. An independent gas regulator was recommended and so was a National Gas Policy Act to be promulgated leading to a Gas Sector Act.

Empirical evidence on Ghana's nascent gas industry is limited to reports prepared by consultants and international agencies, which are mainly to support the government in planning and project financing. Nevertheless, these reports did not take a system-wide view of the gas industry as stakeholder views and concerns were not widely reflected.

Three important issues were absent in these empirical studies. Firstly, whether the current state-dominated structure or an alternative liberalised industry structure is appropriate for a nascent gas industry. Secondly, which regulatory and governance arrangement is capable of incentivising business activities? Finally, what conditions are required for attracting infrastructure investments into the gas industry in Ghana?

Fritsch and Poudineh (2016), provided the only academic work on the natural gas industry development in Ghana, which emphasised on the utilisation options of gas, suggesting a gas-to-power market as a superior strategy. The lack of an effective regulatory framework for investments and the weak institutional framework were identified as major constraints.

Other than Fritsch and Poundineh's (2016) study on gas-to-power development in Ghana, there is hardly any academic work on the Ghana gas industry. This study provides a systematic analysis of structure, business viability and regulation to identify enabling conditions required to support the development of the nascent gas industry in Ghana.

1.2.0. Problem Statement

Nascent gas industries such as Mozambique (100TCF), Tanzania (70TCF) (Demierre et al., 2015) and Ghana (6.4TCF) face similar challenges in limited gas infrastructure investments: lack of local markets and limited domestic demand. Monetising gas resources in the best way possible in these Sub-Saharan African countries is considered challenging (Deierre et al., 2015).

The World Bank Global Gas Flaring Reduction initiative is making efforts to tie associated gas into export projects and to develop local infrastructure to support domestic usage in countries such as Cameroon, Gabon, Equatorial Guinea and Ghana (Ernest and Young, 2013). Nigeria is the fifth largest LNG exporter with vast gas resources but frustrating is the slow pace of exploiting them to meet their domestic energy requirements (Wood, 2016).

Destination LNG markets for West African gas such as the USA are also becoming gas independent due to shale gas production. Consequently, available LNG producers tend to look for alternative markets. Local gas markets and infrastructure in these West African countries with gas resources are emerging to monetize this important resource (Nwaoha and Wood, 2014; Wood, 2016).

However, these gas monetisation efforts are bedevilled with challenges including attracting adequate investments for infrastructure development in domestic gas production and import (LNG) and developing diversified domestic end-user base for gas utilisation which is challenged with unwillingness to pay due to accumulated debt of major off-takers (power sector). The power sector is not financially viable due to tariff control problems and may be unable to honour contractual obligations for gas supply due to their poor financial and technical performance.

Ghana initiated the development of a local gas industry through building midstream and downstream infrastructure to utilise associated gas from the Jubilee Field. Other gas fields such as Tweneboa, Enyenra and Ntomme (TEN) Project and the Sankofa Gas Project were accelerated to meet increasing demand. Inadequate and weak institutional arrangements, lack of regulatory framework for investments, inefficient local pricing (downstream gas and electricity prices) and high risk of infrastructure investments are identified as major problems in the development of Ghana's nascent gas industry.

The power sector is identified as the priority area for the utilisation of Ghana's domestic gas but the power sector faces several challenges of accumulated debt (World Bank, 2013; World Bank, 2015) which is most likely to be transferred into the gas industry. This is a major problem to investors on the viability of the gas industry.

Furthermore, the entire gas value chain in Ghana is state-controlled: dominated by the Ghana National Petroleum Corporation (GNPC), which is selected to be the national gas aggregator, and the Ghana National Gas Company (GNGC), which operates the Gas Processing Plant (GPP) and the 114KM transmission pipeline supplying gas to the Volta River Authority

(VRA) as the consumer. The gas industry value chain, thus, is a GNPC-GNGC-VRA affair, which to the private sector does not provide a fair and a level playing ground and has placed their investments at risk.

The downstream gas industry regulator, Energy Commission has awarded exclusive license to the Bulk Oil Storage and Transportation Company (BOST) as gas transporter and operator of the 114KM transmission pipeline built by GNGC. This has raised several institutional capacity problems among industry players, with BOST and GNGC in a pipeline operation conflict. There is a dilemma between producers, sellers and users of gas in Ghana in who is operating where and what.

Adding to the issues of industry structuring are the problem of a lack of an effective regulatory framework to attract investment and the conflicting roles and responsibilities between state agencies in the gas industry value chain. The Petroleum Commission regulates upstream oil and gas operations through a regulatory framework. However, there are absolutely no regulations for midstream and downstream activities. Midstream infrastructure usage is not regulated and tariffs for the pipeline and GPP usage are not properly formulated.

The quasi-monopoly of the state and the multiple regulatory agencies cause confusion and risk to private investors. This is because the private sector is of the view that the current structure will not be economically and technically efficient for their operations since this structure is directly tied to a debt-ridden electricity sector subject to state inefficiencies.

The crux of the problem therefore, is how Ghana can develop the gas sector while allowing the power sector to meet its needs and where both industries can grow together mutually. Moreover, there is a question of how Ghana can formulate regulatory arrangements that best fit the gas industry and provide a viable business environment for infrastructure investment. In the end, there should be a win-win solution between the state, investors and consumers in developing the nascent gas industry. This leads to the main and specific objectives of the study.

1.3.0. Objectives of the Study

The main aim of the study is to explore the structural and regulatory arrangements required for developing a viable natural gas industry in Ghana.

1.3.1. Specific Objectives

The specific objectives of the study are to:

- Evaluate possible gas industry structures in Ghana.
- Assess the business viability of each component of the gas supply chain.
- Develop suitable regulatory and governance arrangements for the nascent natural gas industry in Ghana.

1.4.0. Contributions of the Study

The study contributes to the existing thinking in the development of the nascent gas industry in Ghana in three ways. Firstly, stakeholder interactions have indicated contrasting perspectives of industry structuring in the state's support for a Single Buyer Model (SBM) compared to more liberalised structures such as Multiple Buyer Models (MBM). These two perspectives are examined to come out with the best-fit industry structure for Ghana. For the downstream segments, an integrated structure at the initial stage is suitable to reduce risks but a transparent regulatory arrangement is required. Nevertheless, once the industry matures a more competitive arrangement may be adopted.

Secondly, the integrated cash flow analysis of the supply components of the gas industry in Ghana exposed irrational tariff systems for the Gas Processing Plant and transmission pipelines and the possibility of lowering these tariffs, which will lead to a much lower downstream gas price. Non-associated gas production is risky in Ghana since it requires the need to maintain a delicate balance in upstream natural gas production prices and government fiscal policy to achieve financial viability.

Thirdly, inconsistencies in regulatory and governance arrangements have been uncovered from the empirical evidence and stakeholder consultations. Alternative regulatory and governance arrangement framework are being explored and developed for the nascent gas industry in Ghana. An independent gas regulatory authority is recommended to solve the challenges associated with the duplication and conflicting roles in the gas industry.

Finally, developing a viable nascent gas industry in Ghana can serve as a suitable template for other nascent gas industries such as those of Mozambique and Tanzania, which discovered commercially viable quantities of gas or countries flaring their natural gas such as Nigeria.

1.5.0. Structure of the Thesis

The balance of the thesis is divided into eight chapters. Chapter Two gives an overview of the development of the nascent gas industry in Ghana. Chapter Three presents the literature review focusing mainly on combining two theories: Structure-Conduct-Performance paradigm (SCP) and the Transaction Cost Economics (TCE) to develop an analytical framework. Chapter Four focuses on the methodology, how the analytical framework is developed with stakeholder engagement using semi-structured guided interviews and the integrated cash flow model.

Chapter Five to Seven are the main thrust of the study, with Chapter Five discussing the first objective of the study: structuring the gas industry. Chapter Six follows with the second objective: business viability of the supply components of the gas industry while Chapter Seven considers the third objective of the study: regulations and governance arrangements. The final chapter, Chapter Eight, provides conclusions based on the analyses and makes recommendations.

1.6.0. Chapter Summary

This chapter, Chapter One, provided the background of the study by introducing the subject of discussion and the on-going thinking in the nascent gas industry in Ghana. The chapter, also, presents the problem statement, the main and specific objectives and the contributions of the study to existing knowledge.

CHAPTER TWO
DEVELOPMENT OF THE NASCENT GAS INDUSTRY IN GHANA

2.0. Introduction

This chapter provides an overview of the development of the nascent gas industry in relations to other sectors of the economy in Ghana. The first section looks at economic development with focus on three main sectors (agriculture, services and industry). The second section considers the energy sector and the emerging gas industry and finally, the conclusion provides a summary.

2.1.0. The Ghana Context

Ghana is located in West Africa with a total land area of 238,540km^2 and shares borders with the Gulf of Guinea and the Atlantic Ocean to the south, a few degrees north of the equator, with Togo to the east, Cote d'Ivoire to the west and Burkina Faso to the north (Siakwah, 2017; AQUASTAT, 2005). The country has a population of 28.21million and a growth rate of 2.2% per annum (Ghana Statistical Service, 2017). Ghana has 10 administrative regions with 45% of the population living in rural areas (UNICEF, 2016).

Ghana practices a multiparty democracy and is noted for a stable political and social environment. In 2017, for instance, Ghana demonstrated her political credentials in a smooth change of power from the National Democratic Party (NDC) to the New Patriotic Party (NPP). Before this feat, Ghana had received praises from international bodies for experiencing a strong, inclusive and sustained economic growth over the past two decades (International

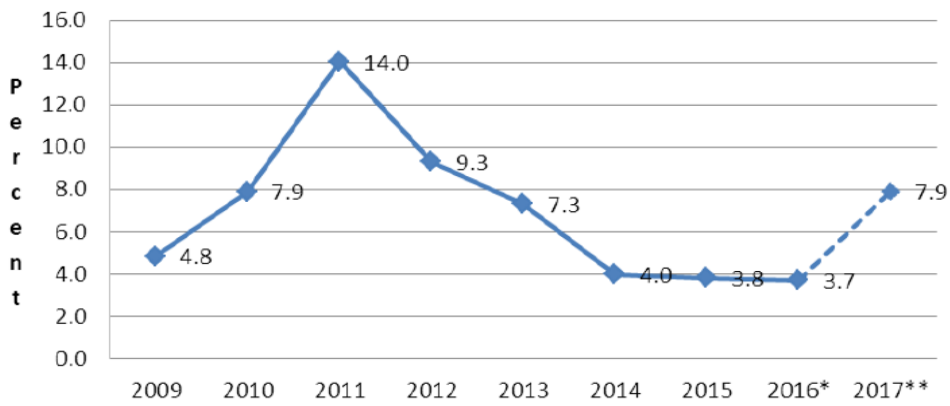
Monetary Fund, 2014; World Bank, 2015).

2.1.1. Economic Development in Ghana

Ghana is a low middle-income country with a Gross Domestic Product (GDP) of US$117.16 billion in purchasing power parity and a per capita income of US$4,150, well above other low middle-income countries in Sub-Saharan Africa (IMF, 2017; World Bank, 2017). About 24.2% of the population live below the poverty line implying that 6.4million Ghanaians are poor (Ghana Statistical Services, 2014).

The average GDP growth rate for Ghana from 2008-2017 is 7.1% as indicated on Figure 1. The overall economy of Ghana is projected to grow at an annual rate of 7.9% in the medium-term from 2017 to 2019 (Ministry of Finance, 2017) assuming restoration of energy supply and recovery of oil and gas production and crude oil prices (African Development Bank, 2017).

Figure 1: Annual Real GDP Growth Rate for Ghana (%) 2008-2017



Source: Ministry of Finance (2017).

GDP growth rate in the medium term in Ghana is favourable, with an average growth rate of 5.3% expected to peak at 8.9% in 2018 (See Table 1) because of the additional oil and gas production volumes from the TEN Project and the Sankofa Gas Project (SGP). Non-oil GDP is expected to grow on average of 5% per annum and increase from 4% in 2014 to 6% in 2018 within the medium term, resulting in a growth rate of 6% in the long-run (IMF, 2017).

Table 1: Annual growth rate of selected economic indicators in Ghana

	2014	2015	2016	2017	2018	2019	2020	2021	2022
GDP (%)	**4**	**3.8**	**3.5**	**5.9**	**8.9**	**5.9**	**5.1**	**5.2**	**5.4**
Non-oil GDP (%)	**4**	**4**	**4.8**	**4**	**5**	**6**	**6**	**6**	**6**
Oil and Gas GDP (%)	**4.5**	**0.9**	**-16.9**	**42.5**	**64.9**	**5.5**	**-3.1**	**-2.7**	**-1.7**
Real GDP per capita (%)	**1.4**	**1.2**	**0.9**	**3.3**	**6.1**	**3.3**	**2.5**	**2.6**	**2.7**

Source: IMF, (2017).

Inflation in 2016 reached 15.4% but declined to 12.1% in 2017 and projected to decline further within the 8±2% band in early 2018 and expected to remain unchanged in the medium term. This is due to exchange rate stability and increases in the monetary policy rates (IMF, 2017). Ghana's budget deficit on cash basis as percentage of GDP was 8.7% in 2016 has reduced to 4.5% in 2017 and expected to remain stable in the medium-term. However, Ghana continues to struggle with a high fiscal deficit, which widens public debt, weakens exchange rates and results in higher financing cost and inflation.

The International Monetary Fund (IMF) extended a US$918million credit facility and technical support to the government of Ghana from 2015-2019[2]. This is expected to help maintain strict fiscal discipline and manage the

[2] IMF signed an Extended Credit Facility with Ghana in 2015 and extended till 2019 aimed to restore debt sustainability and macroeconomic stability and foster high grow and job creation whilst protecting social spending.

increasing budget deficit. Other economic challenges in Ghana include high youth unemployment, high electricity cost, and uncertainties from markets of global commodities and the risk exposure to the overreliance on three major exports (gold, cocoa and oil).

Ghana loses between US$320million to US$920million per annum in productivity (Institute of Statistical, Social and Economic Research, 2014); equivalent to 2% to 6% loss of gross economic growth due to inadequate fuel and unreliable power supply (Power Systems Energy Consulting and Ghana Grid Company, 2010) resulting in power crisis. Inadequate and unreliable fuel supply is identified as the cause of the power crisis (Energy Commission, 2017).

The Ghana Shared Growth and Development Agenda II[3] was introduced as an economic intervention program aimed at ensuring macroeconomic stability in the medium-term and to achieve an average real GDP growth target of at least 10.6% and a non-Oil GDP growth target of at least 9.6% per annum. The industrial, services and agriculture sectors are identified to lead the projected growth with average annual growth rates of 13.2%, 10% and 6% respectively. It is believed that maintaining debt sustainability, ensuring adequate and reliable power supply and realignment of government expenditure to more productive areas are required for macroeconomic stability in Ghana (IMF, 2017).

[3] The Ghana Shared Growth and Development Agenda II is set to provide a medium to long-term strategic development plan for Ghana. GSGDA II (2014-2017) is a successor to the GSDA I (2010-2013).

2.2.0. Structure of the Ghanaian Economy

The composition of the Ghanaian economy is made-up of the services, agriculture, and industrial sectors. The Ghanaian economy shows a positive outlook for all the three major sectors growing consistently over the past decade (2006-2016) as indicated on Table 2.

Table 2: Structure of Ghana's Major Economic Sectors (%)

Item	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Agriculture	30.4	29.1	31	31.8	29.8	25.3	22.9	22.4	21.5	20.3	18.9
Industry	20.8	20.7	20.4	19	19.1	25.6	28	27.8	26.6	25.1	24.3
Services	48.8	50.2	48.6	49.2	51.1	49.1	49.1	49.8	51.9	54.6	56.8

Source: Ghana Statistical Service (2017).

The agriculture and the industry sectors have the potentials of increasing in growth capacities. The services sector has consistently contributed significantly to more than half of the GDP growth in Ghana being 56.8%; the industry sector, 24.3% and agriculture, 18.9%.

2.2.1. Service Sector Development

The service sector continues to be the leading contributor to economic growth, increasing to 56.8% in 2016 and employs 31% of the economically active population (UNIDO, 2013; Ministry of Finance, 2017). The service sector is composed of finance and insurance; trade, repair of vehicles and household goods; hotels and restaurants; information and communication; education, health and social work; transport and storage; government services, defence and social security and producers of private non-profit services (UNIDO, 2013; Ministry of Finance, 2017).

The leading contributors to the growth of the service sector in 2016 are Transport and storage (13.3%); Financial and insurance activities (9.4%); Trade, Repair of Vehicles, Household Goods (6.4%) and Public Administration and Defence; Social Security (5.4%) as indicated on Table 3. Transport and storage sub-sector is the leading contributor to the services sector growth.

The oil and gas industry can be aligned with the services sector in providing stable, reliable and cheap electricity to most of the services sub-sectors; for example, financial services and insurance; education; health and social work; real estates and support services and public administration, defence and security. The transport and storage sub-sector can benefit from using natural gas to produce methanol and auto-gas as alternative transport fuels. Liquefied Petroleum Gas (LPG) from the gas processing plant is used as cooking fuel in households, hotels and restaurants as well as health facilities such as hospitals. The tourism industry will benefit immensely when hotels and restaurants have a stable and cheap power supply.

The financial and insurance sub-sector is insulated from providing letters of credit (LC's) to the Volta River Authority (VRA) for the purchase of Light Crude Oil (LCO) if the gas industry can function properly in providing sufficient quantities of fuel to thermal plants. This, in the long-run, will reduce the debt burden of VRA on financial services with reserved capital being reinvested into other sectors of the economy for optimal economic growth.

Table 3: Services subsector contribution to GDP (%)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
SERVICES	48.8	50.2	48.6	49.2	51.1	49.1	49.1	49.8	51.9	54.6	56.8
Trade; Repair of Vehicles, Household Goods	6.4	6.1	6	5.9	6.2	5.9	5.6	5.8	5.6	6.1	6.4
Hotels and Restaurants	5	5.6	6	6.2	6	5.4	4.8	5.8	5.6	5.8	5.9
Transport and Storage	13.2	13.1	11.4	10.5	10.6	10.7	11	11.2	12.3	13	13.3
Information and Communication	2.7	2.4	2.2	1.8	1.9	1.8	2.2	1.7	2.3	2.7	3.3
Financial and Insurance Activities	2.7	3.4	3.8	4.3	5.2	4.4	4.7	6.5	8.4	8.9	9.4
Real Estates, Professional & Administrative Services	5.1	4.7	4.1	4.1	4.5	4.6	4.8	3.9	3.6	3.6	4
Public Administration & Defence; Social Security	4.8	5.9	6.3	7	7	7	6.8	5.9	5.4	5.3	5.4
Education	3.7	3.9	3.9	4.2	4.3	4.1	4.3	3.6	3.6	3.7	4
Health and Social Work	1.4	1.4	1.3	1.4	1.6	1.3	1.3	1.1	1	1.2	1.4
Community, Social & Personal Service Activities	3.7	3.7	3.6	3.7	4	3.9	3.7	4.3	4.1	3.8	3.7

Source: Ghana Statistical Service (2017).

2.2.2. Agricultural Sector Development

The agriculture sector comprises five sub-sectors, namely, crops, livestock, cocoa, fisheries and forestry/logging. The agriculture sector accounts for about 44.7% employed population largely dominated by women (Ghana Statistical Service, 2015). The sector contributed about 18.9% to Ghana's GDP in 2016, a significant decline from 30.4% in 2006 (See Table 2). The crops sub-sector has been the major contributor to the sector's GDP growth followed by forestry/logging and cocoa with 14.5% and 2.1% respectively in 2016.

The agriculture development policy of Ghana focuses on the modernisation of agriculture and increasing productivity of farmers. The policy intends among other items to accelerate the development of selected food crops, improve access to mechanisation and enhance access to inputs (Ministry of Food and Agriculture, 2007).

Table 4: Agriculture subsector contribution to GDP (%)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
AGRICULTURE	**30.4**	**29.1**	**31**	**31.8**	**29.8**	**25.3**	**22.9**	**22.4**	**21.5**	**20.3**	**18.9**
Crops	**21.3**	**20.3**	**22.4**	**23.6**	**21.7**	**19.1**	**17.2**	**17.4**	**16.8**	**15.7**	**14.5**
o.w. Cocoa	**3**	**2.7**	**2.5**	**2.5**	**3.2**	**3.6**	**2.6**	**2.2**	**2.2**	**1.8**	**1.7**
Livestock	**2.5**	**2.3**	**2.1**	**2**	**2**	**1.8**	**1.6**	**1.4**	**1.2**	**1.2**	**1.2**
Forestry and Logging	**4.1**	**4.2**	**3.7**	**3.7**	**3.7**	**2.8**	**2.6**	**2.2**	**2.3**	**2.3**	**2.1**
Fishing	**2.5**	**2.3**	**2.7**	**2.5**	**2.3**	**1.7**	**1.5**	**1.4**	**1.2**	**1.2**	**1.1**

Source: Ghana Statistical Service (2017).

The crops and livestock subsectors are expected to lead the sector's growth agenda with an annual projected growth rate of 6% (Ministry of Food and Agriculture, 2007). Programs such as fertilizer subsidies, agriculture mechanisation and irrigation development programs are intended to lead the agenda (Food and Agriculture Organization, 2015). The fertilizer subsidy program covers 50% of fertilizer prices to farmers and the government of Ghana spends about US$ 63 million yearly on this program (Food and Agriculture Organization, 2015).

The crops (cereals, rice, maize, millet, etc.) subsector and cocoa production are the main areas that require the intensive application of fertilizers to lead the mechanisation agenda. The main fertilizers imported into the country include Nitrogen-Phosphorus-Potassium (NPK), Urea, Potash, Nitrate and

Sulphate. Total fertilizer imports in 2016 stood at about 239,886metric tonnes (AfricaFertilizer.org, 2017).

There is a complementary relationship between the oil and gas industry and the agriculture sector as both sectors can be strategically aligned for mutual benefits especially in the production of fertilizers where natural gas can be used as feedstock for the development of a fertilizer manufacturing plant and indirectly in agro-processing industries. This comes in the form of an integrated gas-to-fertilizer development whereby upstream natural gas production is linked to a downstream ammonia/urea production plant and make available cheap and reliable electricity to agro-processing industries.

Additionally, electricity demand for agro-processing, for instance, in fish, fruits and vegetable processing and storage, livestock processing and storage and value addition to cash crops such as cocoa, palm oil and other cereal crops before export may increase.

Adequate, cheap and reliable natural gas supplies are required in the long-run as feedstock to the fertilizer plant and to thermal plants to produce electricity at competitive tariffs and reliably to make the agro-processing industries in Ghana globally competitive. In the long-run, if the gas industry and the agriculture sector are well integrated, this can transform the agriculture sector into a high-value addition sector through an agro-processing industrial development agenda. These activities can accelerate the agriculture sub-sector's contribution to GDP and help maintain the long-term economic growth and macroeconomic stability of Ghana.

2.2.3. Industrial Sector Development

The composition of the industrial sector in Ghana includes Mining and Quarry, Oil and Gas, Manufacturing, Electricity, Water and Sewerage and Construction. The industry sector contributed about 24.3% to GDP in 2016, a decline from the past four years' of 28% in 2012 (See Table 2). The Industrial sector employs about 7.5% of the population and steady growth from 20% to 24.3% over the past decade (2006 to 2016).

The Construction subsector has been the leading contributor of growth of the Industrial sectors, contributing 13.7% to GDP growth in 2016. The introduction of the Oil and Gas subsector in 2010 saw the industrial sector contribution to GDP increasing from 19% in 2010 to about 27.8% in 2013. The Oil and Gas industry even though emerging displayed consistent growth patterns until between 2015 to 2016 where the sector experienced contraction due to falling global crude oil prices[4], slowed investments and price volatility.

[4] Crude oil prices experienced sharp falls from US$115/barrel in June 2014 to under US$35/barrel in February 2016 and this has been attributed largely to supply-demand imbalances (World Economic Forum, 2016).

Table 5: Industry subsectors contributions to GDP (%)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
INDUSTRY	20.8	20.7	20.4	19	19.1	25.6	28	27.8	26.6	25.1	24.3
Mining and Quarrying	2.8	2.8	2.4	2.1	2.3	8.4	9.5	9.4	8	5.3	4.2
o.w. Oil	0	0	0	0	0.4	6.7	7.7	8.2	7.2	4.1	2.1
Manufacturing	10.2	9.1	7.9	6.9	6.8	6.9	5.8	5.3	4.9	4.8	4.6
Electricity	0.8	0.6	0.5	0.5	0.6	0.5	0.5	0.4	0.4	0.9	1.1
Water and Sewerage	1.3	1	0.8	0.7	0.8	0.8	0.7	0.6	0.5	0.6	0.5
Construction	5.7	7.2	8.7	8.8	8.5	8.9	11.5	12	12.7	13.5	13.7

Source: Ghana Statistical Services (2017).

The Electricity subsector experienced sudden growth in 2015 from a marginal 0.9% to 1.1% in 2016 due to the availability of domestic natural gas as fuel to existing thermal plants. Natural gas from the Oil and Gas subsector can be used to further accelerate the growth of the electricity sector by providing reliable and cheap fuel to thermal plants.

Ghana's industrial policy as approved by parliamentary cabinet in 2010 is set on transforming the country into an industrial development model capable of delivering widespread jobs, equity, growth and poverty reduction and a vision aimed at supporting Ghana to become a leading agro-industrial country (Ministry of Trade and Industry, 2011; UNIDO, 2013). The policy aims at tackling several challenges confronting the Manufacturing sector such as increasing production capacity and product quality and enhancing global competitiveness (Ministry of Trade and Industry, 2010).

The industrialisation policy of Ghana can complement the gas industry to develop a policy that serves as a catalyst to provide reliable and lower cost energy directly to support the Manufacturing and Electricity subsectors and as a feedstock to develop a new growth pole of petrochemical industries. There are possibilities of linking the gas industry to the Manufacturing subsector through an integrated aluminium production, petrochemical processes, direct salt-driven health and food industries, caustic soda based industries, feedstock for fertilizer production, lower cost energy to small industries and agro-processing industries. Gas-driven energy can support large-scale industries for growth and development in Ghana (Emos, 2010).

2.3.0. Overview of the Energy Sector in Ghana

The energy balance[5] in Ghana is multifaceted and composed of crude oil, oil products, natural gas, biofuels and waste, hydro, and electricity (IEA, 2017). The main primary energy sources in Ghana are petroleum and biofuel waste, which account for 46.7% and 37.2% respectively. Hydro remains at 5.2% and natural gas contribute 10.6% (IEA, 2017).

The petroleum subsector in crude oil production, oil products and natural gas are the main source of energy in Ghana. Thousands of tonnes of oil equivalent (ktoe) of 5659ktoe crude oil is produced domestically with majority of 5303ktoe exported and only 356ktoe remaining while additional 317ktoe is imported. Majority of the crude oil is transferred to electricity generators (253ktoe) and to oil refineries (112ktoe). Oil products in Ghana are imported (4063ktoe) and (130ktoe) exported to neighbouring land lock countries (Burkina Faso and Niger). Part of the oil is also used for international marine bunkering (128ktoe) while the remaining (3763ktoe) is used for domestic

[5] Energy balance of a country is the overall patterns of energy supply and use (IEA, 2017).

consumption mostly in transportation (2619ktoe), industry (583ktoe) and others as indicated on Table 6.

Natural gas is produced locally (468ktoe) and imported (596ktoe) which are transferred to electricity production. Hydropower generation (503ktoe) is constant. Crude oil, gas and hydro are the main sources of energy transfers for electricity generation in Ghana. Crude oil produced in Ghana is exported with only small volumes remaining to be supplemented with imports for power generation and refinery's operations. Gas remains the most viable energy source transferred to electricity plants in Ghana as all domestically produced and imported gas are transferred to power generation (see Table 6).

An estimated 3617ktoe of biofuels and waste are produced in Ghana. Biofuels and waste energy are consumed as fuels in the residential sector (1885ktoe) and for other purposes (2018ktoe). About 1195ktoe of biofuels and waste are transferred to other forms of energy. Much as it is a source of indirect livelihood for over 3million Ghanaians, especially women (65%), its adverse health and environmental implications are well documented (Energy Commission, 2013).

Table 6: Energy Balance of Ghana for 2015 (ktoe)

	Coal	Crude Oil	Oil Products	Natural Gas	Nuclear	Hydro	Geothermal, Solar, etc	Biofuels and Waste	Electricity	Heat	Total
Production	0	5659	0	468	0	503	0	3617	0	0	10247
Imports	0	317	4063	596	0	0	0	0	19	0	4995
Exports	0	-5303	-130	0	0	0	0	0	-47	0	-5480
International Marine Bunkers	0	0	-128	0	0	0	0	0	0	0	-128
Stock changes	0	0	62	0	0	0	0	0	0	0	62
TYPES	0	673	3868	1064	0	503	0	3617	-28	0	9696
Transfers	0	0	0	0	0	0	0	0	0	0	0
Statistical differences	0	-307	-196	0	0	0	0	0	-5	0	-508
Electricity Plants	0	-253	0	-1064	0	-503	0	0	988	0	-832
CHP plants	0	0	0	0	0	0	0	0	0	0	0
Heat plants	0	0	0	0	0	0	0	0	0	0	0
Gas works	0	0	0	0	0	0	0	0	0	0	0
Oil refineries	0	-112	97	0	0	0	0	0	0	0	-15
Coal Transformation	0	0	0	0	0	0	0	0	0	0	0
Liquefaction plants	0	0	0	0	0	0	0	0	0	0	0
Other transformation	0	0	0	0	0	0	0	-1195	0	0	-1195
Energy Industry own use	0	0	-5	0	0	0	0	0	-6	0	-11
Losses	0	0	0	0	0	0	0	0	-205	0	-205
Total Final Consumption	0	0	3763	0	0	0	0	2422	744	0	6929
Industry	0	0	583	0	0	0	0	407	356	0	1347
Transport	0	0	2619	0	0	0	0	0	0	0	2619
Other	0	0	395	0	0	0	0	2015	387	0	2797
Residential	0	0	281	0	0	0	0	1885	210	0	2376
Commercial and Public Service	0	0	36	0	0	0	0	128	178	0	342
Agriculture/forestry	0	0	70	0	0	0	0	2	0	0	72
Fishing	0	0	7	0	0	0	0	0	0	0	7
Non-specified	0	0	0	0	0	0	0	0	0	0	0
Non-energy use	0	0	166	0	0	0	0	0	0	0	166
of chemical/petrochemical	0	0	0	0	0	0	0	0	0	0	0

Source: International Energy Agency (2015).

The Electricity subsector constitutes activities related to electricity generation, transmission and distribution and efficiency/conservation. Electricity accounts for 47% of total energy consumed in households and 65.6% of modern energy to the Industrial and Service sectors in Ghana (Ministry of Energy, 2010). The leading electricity consuming sectors in Ghana include the 'Other sectors' (residential, commercial, public service, agriculture/forestry, fishing and non-specified) (387ktoe), Industrial sector (356ktoe), the Residential sector (210ktoe) and Commercial and Public services (178ktoe) and about 205ktoe of electricity, however, is lost during transmission.

Transmission losses occur when power is transferred from generators to loads and there are two types of losses: technical and commercial. Technical losses are largely caused by energy dissipated as heat in the resistive conductors and equipment used for transmission, transformation and distribution of power. Commercial losses include pilferage, defective meters and errors in accounting for electricity consumption (Power Systems Energy Consulting and Ghana Grid Company Limited, 2010).

The Energy Commission (2017) estimated on average 607.38GWh transmission losses per year under a review period between 2014-2016 representing 4.4% as indicated on Table 7, compared to PURC 4% requirements and far below the industry rule-of-thumb of 3% (PSEC and GRIDCo, 2010). International Energy Agency (2014) noted that Sub-Saharan African countries electricity transmission and distribution losses are twice the global average of 8%. OECD countries have an average of 6%. European Union has an average of 6%. UK and U.S recorded 8% and 6% respectively. Ghana on the other hand records 23% of transmission and distribution losses (World Bank, 2018).

Table 7: Transmission Losses in Ghana (2014-2016)

Year	**2014**	**2015**	**2016**
Transmission Losses %	4.22	3.79	4.4

Sources: Energy Commission (2017).

The increase in transmission losses were mainly due to lack of adequate generation to allow for geographical balance in generation in operation at all times and due to congestion. High transmission losses in Ghana are mainly because of heavy power flows due to limited transmission capacity (PSEC and GRIDCo, 2010). Distribution losses in Ghana accounts for approximately 24% of demand driven largely by technical and commercial losses compared to the US, losses of only 6.5% of demand (PSEC and GRIDCo, 2010). The World Bank (2013) report estimated Ghana's largest electricity distributors- Electricity Company of Ghana (ECG) distribution losses of 27% (technical and non-technical) of which 16% are non-technical.

Access, availability and affordability related issues are cited as underlying reasons for the dominance of fuel usage in Ghana. The Oil and Gas, Electricity and Renewable energy subsectors are strongly supplementary given the dependence of the power sector on oil and gas for fuel and solar Photovoltaic (PV) for power generation. The commercialisation of gas resources in Ghana is driven by the power sector's need for a less expensive alternative fuel. The Oil and Gas sector in Ghana can be integrated into the Electricity sector where both natural gas and LCO are sourced domestically. Further analysis is made on the interrelationship between the gas industry and electricity subsector explained in the following section.

2.3.1. Electricity Sector Institutions in Ghana

Ghana unbundled its Electricity sector into generation, transmission and distribution and was one of the first countries in Sub-Saharan Africa to attract private investment through Independent Power Producers (IPPs) in electricity generation (PSEC and GRIDCo, 2010). The institutional setting of the electricity subsector in Ghana includes as indicated on Table 8, the Ministry of Energy has policy, monitoring and regulatory oversight responsibilities. The Volta River Authority (VRA), a state-owned utility is the dominant electricity producer responsible for 2,456MegaWatts (MW) of installed generation capacity which represents (56%) from hydro, solar and thermal sources.

There are several other IPPs accounting for the remaining 1,927MW (43.9%) of installed generation capacity from thermal and solar sources (VRA, 2015). Several other upcoming IPPs are planning to add generation capacity of 2025MW, which will shift Ghana's electricity generation capacity towards reliance on IPPs. The State-owned Grid Company Limited (GRIDCo) is the sole transmission company. The Electricity Company of Ghana (ECG) and Northern Electricity Distribution Company (NEDCo) are the electricity distribution companies for South and Northern zones of Ghana respectively. The Public Utilities Regulatory Commission (PURC), is the economic/financial regulator whilst Energy Commission provides technical regulations.

Table 8: Electricity Subsector Institutions in Ghana

Institutions	Responsibilities	Sector
Ministry of Energy	-responsible for formulating, implementing, monitoring and evaluating energy sector policies	Energy Sector
Energy Commission (EC)	-Technical Regulator	Energy Sector
Public Utilities and Regulatory Commission (PURC)	-Economic/Financial Regulator	Utilities sector
Volta River Authority (VRA)	-manages hydropower, thermal and solar PV assets generation capacity	Power Sector
Ghana Grid Company (GRIDCo)	-Owns and operates the High Voltage transmission system	Power sector
Electricity Company of Ghana (ECG)	-controls 70% of retailing electricity sales in the Southern Zone of Ghana	Power sector
Northern Electricity Distribution Company (NEDCo)	-a subsidiary of VRA which handles power retailing in the Northern Zone of Ghana	Power sector
Independent Power Producers (IPPs)	- Thermal power and Solar PV generation	Power sector

Source: Ministry of Energy (2015).

2.4.0. Overview of the Electricity Subsector in Ghana

Ghana's electricity generation mix is made-up of hydropower, thermal and renewable energy (solar PV). Installed capacity in 2017 stands at 4,577MW and dependable capacity is 3,944MW. The dependable capacity generation mix has hydropower, 1,380MW (34.9%), thermal 2,564MW (65%) which indicates the increasing role of thermal generation in providing dependable electricity. Electricity access in Ghana stands at 83.24% and consumption per capita is estimated at 344 kilowatts hours (kWh) whilst peak demand has increased from 1,933MW in 2015 to 2,386MW in 2017 (Ministry of Finance, 2017).

The main feature of electricity generation in Ghana is its dependence on hydropower for base-load generation capacity, which makes it vulnerable to unreliable supply due to rainfall shortfalls. The introduction of liquid fuel based thermal power as a short-term measure has increased the cost of supply and reduced sector viability. The sector has not seen major capacity growth in the past two decades due to the poor financial condition of the main utilities (VRA and ECG) as discussed further. The deregulation of the sector has not been able to resolve the sector's problems. The lack of reliable electricity supply has negative implications for the economy as it causes nearly 2% to 6% per annum reduction in GDP growth rate in 2012 to 2016 (Ministry of Finance, 2017).

Light Crude Oil (LCO) was imported as fuel for thermal power generation. Liquid fuels proved expensive and reduce the viability of these thermal plants especially when crude oil prices are above US$85/barrel. The fuel composition of the thermal plants includes other fuels apart from LCO such as heavy fuel oil, distillate fuel oil and natural gas. On one hand, about US$1.2billion is required annually to procure fuel for all the thermal plants in Ghana (Energy Commission, 2017). This increasing cost affected the viability of the Volta River Authority (VRA) resulting in lower thermal capacity growth.

In the medium term (up to 2022), total electricity demand in Ghana is projected to peak at 3,828MW and total supply required (demand + reserve margin) is projected at 4,784MW. Hydro generation is limited to dependable generation capacity estimated at 1,120MW as indicated on Table 9. Thermal and solar generation are the key supply options to meet the remaining electricity demand, with solar generating a marginal 22.5MW up to year 2022.

Table 9: Medium Term Electricity Projections

Year	2018	2019	2020	2021	2022
Projected Demand (MW)	2646	3128	3462	3712	3828
Total Supply Required (Demand + Reserved)	3308	3910	4327	4640	4784
Total Existing Hydro Capacity (MW)	1120	1120	1120	1120	1120
Total Existing Thermal Capacity (MW)	2360	2462	2462	2462	2462
Total Existing Renewables	22.5	22.5	22.5	22.5	22.5
Expected Total Generation (MW)	4326.5	4704.5	4804.5	4805	4804.5
Surplus (MW)	1019	794	477	165	20

Sources: Energy Commission et al. (2017).

Thermal generation is the immediate option to meet the increasing demand, which is projected to increase from 2,360MW in 2018 to 2,462MW in 2022. Additional fuel (Light Crude Oil, Distillate Fuel Oil (DFO), Heavy Fuel Oil (HFO) and natural gas) will be required. Additionally, about 2025MW of planned thermal generation capacity are committed by various IPPs as indicated on Table 10. These planned capacities are thermal plants and emergency power barges, which will also require LCO, HFO, DFO and gas. This will lead to increased LCO/HFO/DFO importation, additional domestic gas production, increased WAGP supplies or additional gas supply capacities.

Table 10: Planned/New Power Generations Projects in Ghana

Planned/Developer	Power Generation (MW) type of capacity	Assumed Start Date
Amandi	240	2018
Jacobsen	360	2018
EDF/VRA	200	2017
Ghana1000	375	2018/19
Globeleg	375	2019
Karpower 2	225	2016
APR Emergency Power Rental	250	2015/16
Total	2025MW	

Source: Volta River Authority, (2016).

Majority of these thermal plants are combined cycle plants using either LCO or natural gas as indicated on Table 11. The power sector presents a major market for both domestic LCO and gas production. The petroleum sector can provide a mutually beneficial relationship with the power sector in supplying LCO instead of exports (see Table 6) and gas to thermal power plants in Ghana. However, gas presents a more viable option for the power plants in electricity generation.

Table 11: Total Electricity Generation Capacity in Ghana (MW)

Power Plant	Installed Capacity (MW)	Dependable Capacity (MW)	Type	Fuel Type
Volta River Authority				
Akosombo	1020	900	Hydro	Water
Kpong	160	140	Hydro	Water
VRA Solar	2.5		Solar	Sun
TAPCO(T1)	330	300	Thermal	LCO/Gas
TICO(T2)	330	320	Thermal	LCO/Gas
T3	132	120	Thermal	LCO/Gas
TTIPP	110	100	Thermal	LCO/Gas
TT2PP	49.5	45	Thermal	DFO/Gas
Tema Thermal 2 Expansion TT2-PPX	22	19	Thermal	Gas
Kpong Thermal Power Plant – KTPP	220	200	Thermal	Gas/DCF
MRP	80	70	Thermal	DFO/Gas
Independent Power Producers				
Bui HEP	400	340	Hydro	Water
AMERI	250	230	Thermal	Gas
Karpower Barge 1	225	220	Thermal	HFO
Sunon Asogli Phase 1	200	180	Thermal	Gas
Sunon Asogli Phase 2 Stage 1	180	160	Thermal	Gas
Sunon Asogli Phase 2 Stage 2	180	160	Thermal	Gas
CENIT	110	100	Thermal	LCO
AKSA	360	340	Thermal	HFO
BXC Solar	22			Sunlight
Total Installed Capacity	4383			
Planned Capacity	2025			
Total Dependable Capacity		3944		

Source: VRA (2017). LCO-light crude oil, HFO-heavy fuel oil, DFO-distillate fuel oil

How much gas can be made available to existing and planned thermal plants in Ghana? In addition, how much additional natural gas capacity is required? For the electricity sector to be able to respond to the gas industry, the sector should be able to pay for the gas consumed through economically efficient tariffs. The next section throws lights on the challenges of the electricity subsector in Ghana.

2.4.1. Challenges in the Electricity Sector in Ghana

The power sector faces two main challenges arising from forces external to the sector: the lack of adequate and secured quantities of reasonably priced fuel for power generation and the lack of adequate public funds to finance the sector investments requirements (World Bank, 2013). The challenges are exacerbated by several constraints, principally in poor technical and financial performance of the main utilities (VRA and ECG) due to accumulated debt burdens, high cost of operations and higher levels of inefficiencies. Additionally, the sector faces poor tariff collection by ECG.

About US$4billion, investments in power sector infrastructure are required in Ghana over the next 10years to make up for the current deficit and upgrade existing infrastructure. IPPs are key sources of generation sector investments in Ghana but are constraint by lack of reliable gas supply, poor regulatory and governance frameworks, lack of credible off-takers, lack of credible regulatory procedures to ensure payments increasing investments risk (World Bank, 2015).

ECG and NEDCo suffered from subsidised electricity tariffs to consumers over the years in their tariff collection responsibilities. ECG is a large centralized state entity with serious weaknesses in its management, corporate governance and institutional culture. Residential and commercial tariffs collections are low in Ghana mainly due to technical and non-technical reasons (transmission and distribution losses, pilfery, poor economic tariffs, poor tariffs collection and institutional weakness) as a result ECG depended largely on revenues from non-residential consumers who account for 56% of sales revenues even though they account for 12% of ECG sales unit. PURC failed attempts to increase retails tariffs resulted in ECG recording losses of US$44million in 2012 and US$60million in 2013(World Bank, 2013).

Table 12: ECG Income Statement 2010 - 2014

In Ghana Cedis Millions	2010	2011	2012	2013	2014
Total Revenues	975	1,207	1,422	1,939	3,114
Power purchases	(591)	(693)	(817)	(1,189)	(1,826)
Transmission Costs	(119)	(171)	(198)	(218)	(329)
Distribution, operation and maintenance	(67)	(100)	(126)	(184)	(210)
Transport costs	(11)	(16)	(21)	(31)	(32)
Overhead costs (mostly staff costs)	(73)	(118)	(156)	(203)	(239)
EBITDA	115	109	105	114	478
Depreciation and Amortization	(76)	(150)	(199)	(237)	(285)
EBIT	39	(40)	(94)	(123)	193
Net Interest	1	(2)	3	(12)	(66)
Foreign Exchange Difference	11	(15)	(17)	(78)	(215)
Tax Credit/Expense	(46)	34	(28)	(40)	(2)
Net Income	6	(24)	(136)	(254)	(90)

Source: World Bank, (2015).

Revenues for ECG more than tripled US$690million, which are mainly due to increases of about 45% volumes, billed and 112% tariffs increments. Increased receivables from public sector also increased to US$256million in 2014. ECG short-term reliabilities to power purchases (VRA) increased to

US$1.1billion at the end of 2014 as ECG failed to pay VRA for power deliveries. ECG made losses from 2011 to 2014 as indicated on Table 12.

VRA makes twice as much profits when they sale electricity to the mining companies compared to sales to ECG. VRA profitability is linked to sales to the mining sector. VRA operating expenses are linked to hydrological factors: water levels in the hydro dams, VRA buys more LCO for the thermal plants and the lower crude oil prices, the lower VRA operating expenses.

Table 13: VRA Income Statements 2010-2014

In Ghana Cedis Millions	**2010**	**2011**	**2012**	**2013**	**2014**
Total Revenues	1,114	1,159	1,357	1,516	2,207
Hydro expenses	(10)	(15)	(19)	(24)	(31)
Thermal expenses	(752)	(618)	(796)	(979)	(973)
Electricity purchases	-	-	(634)	(608)	(569)
Admin expenses	(166)	(202)	(208)	(217)	(436)
Other	(55)	(72)	-	-	-
EBITDA	131	252	(300)	(311)	198
Depreciation	(78)	(112)	(75)	(105)	(158)
EBIT	53	140	(375)	(416)	40
Net Interest	(30)	(35)	(49)	(75)	(320)
Foreign Exchange Difference	17	(22)	2	(121)	(481)
Tax Credit/Expense	-	-	-	-	-
Net Income before Government subsidy	41	83	(421)	(612)	(761)
Government subsidy	-	-	361	664	298
Net Income	41	83	(61)	52	(462)

Source: World Bank, (2015).

VRA has historically been in low debt, but in 2014 due to ECG non-payments VRA has gone for short and long-term debts to offsets their fuel liabilities. VRA cash flows suffers from late payments by ECG. By the end of 2014 VRAs, receivables from ECG reached US$0.9billion of revenues. The increases in these receivables resulted to VRA negative cash flows from operations since 2011, including Ghana Government subsidies. VRAs debt by the end of 2014 stood at US$1.1billion of which half are short-term debts. VRA viability and profitability are unstable and inconsistent as indicated on Table 13 and ECG is the single largest company indebted to VRA.

IPPs are exposed to the risk of the inefficiencies of both VRA and ECG. IPPs are as well exposed to the risk accumulated debt between VRA and ECG since VRA is the purchaser of IPPs generated electricity. Alternatively electricity generated from the IPPs can be channelled to the mining companies which are having the ability and willingness to pay for secured power. This will also serve as a guarantee for IPPs power and therefore reduce the risk of non-payments of IPPs power generated in Ghana and this could be a solution to attracting more power sector investments.

VRA and ECG are increasingly becoming non-creditworthy off-takers of wholesale electricity and gas supply in Ghana, which is a major obstacle for VRA to reach financial closure with new IPPs for power generation and gas suppliers (World Bank, 2015). Table 14 indicates the debt accumulated in the Electricity sector as this hampers guaranteed and timely payments for power and gas supplied and increases power/gas sector investment risks in Ghana.

Table 14: Accumulated Debt in the Power Sector in Ghana

Debt	Description
1. US$1.1billion	Public sector liabilities of electricity bills to ECG
2. ECG owes 60% liabilities	To power suppliers: IPPs and GRIDCO
3. US$330million and US$180million	VRA owes to three major banks (Ecobank, Stanbic Bank and Standard Charted Bank)
4. US$162million	VRA owes N-Gas and WAGPCo for gas supply
5. US$250million	Sunon Asogli owes VRA for gas supply
6. US$306.10million	VRA owes Ghana National Gas Company for gas

Source: Ministry of Finance-Ghana (2017); Ministry of Energy (2015).

Inefficiencies in state Institutions such as ECG and VRA, PURC, Ministry of Energy and Energy Commission and the public sector delays in electricity tariffs non-payment as well contributes to the power sector challenges. Electricity is considered a public good[6], provided by the state, the public sector is unable to pay economic tariffs or delaying electricity tariffs payments. Alternative arrangements can be made to supply electricity from less expensive sources such as hydrodams to the public sector and the residential sectors. Whilst the more expensive thermal plants can be offered to the mining companies and otherss who are willing and able to pay the more expensive electricity tariffs.Government can as well offer subsidies to rural communities and urban poor communities through off-grid solar PVs or direct subsidizes of lower electricity tariffs.

The gas industry is hit severely by this accumulated debt from VRA, which is the monopsony buyer of domestically produced gas and is unable to

[6] Public Good (nonrival and nonexclusive): economist regards goods or service as having public good characteristics if onces they are created they are available to all consumers and cannot be withheld from one individual without withholding it from all. Nonrival is when additional consumers do not add to cost. Nonexclusive is when people cannot be excluded from consuming it (Abbot, 2001).

pay West Africa Gas Pipeline Company (WAPGCo), Nigerian-Gas (N-Gas) and Ghana Gas Company Limited (GNGC) for gas purchases. Additional natural gas capacities from the Floating Storage Regasification Unit (FSRU) for Liquefied Natural Gas (LNG) importation are required. The constraints in the electricity sector need to be reduced for the sector to be viable.

The Government of Ghana through the IMF credit facility in 2015 and the Millennium Challenge Account (MCA) Compact II agreed to reduce the short-term payment arrears of ECG and introduce reforms into electricity retailing in Ghana. This will enable ECG to reduce its debt to major suppliers particularly VRA (World Bank, 2015). This is an important signal to the current situation in the natural gas industry and the pathway to restoring credibility and eliminating the risk of non-payments and debt accumulation.

Therefore, the financial viability of the major state utilities in the downstream electricity sector is required for the viability of the gas industry. Additionally, the downstream segment is the main source of revenue mobilisation for the electricity and gas industries. Unless economic tariffs for power are charged with full cost recovery for the private sector, attracting additional IPPs and sustaining adequate and reliable natural gas supplies will be problematic in Ghana.

On the other hand, Ghana has one of the highest retail electricity tariffs US$0.15/kWh far above the average price US$0.04/kWh in Sub-Saharan Africa (African Centre for Energy Policy, 2017). This makes industrial development uncompetitive since it requires low cost of energy and flexibility for adjustment in tariffs to economic levels.

This high cost of electricity tariffs comes from short-term power generation facilities through emergency power barges, which depend on liquid fuels and the inefficiencies in state power utilities causing high technical and non-technical losses. An abundant supply of domestic natural gas resources in Ghana is seen as among other solutions a panacea to restoring stability and delivering lower cost energy in Ghana. The next section throws more light on the emerging gas industry in Ghana.

2.5.0. Natural Gas Industry Investment Outlook in Ghana

The total natural gas reserves in Ghana are estimated at 6.4Trillion Cubic Feet (TCF), made up of 2.2TCF of associated gas and 4.2TCF of non-associated gas (Ministry of Energy, 2012). Since 2010, Ghana has been in the process of developing a local gas industry through building midstream and downstream infrastructure to utilise associated gas from the Jubilee Field. Other gas fields such as the TEN and the Sankofa Gas Projects (SGP) are accelerated to meet local demand for power generation.

Within a short spectrum (2010-2017), the gas industry in Ghana witnessed massive investments in US$7.9billion from World Bank and ENI-Ghana investment into SGP; over US$1billion Chinese Development Bank loan facility into the construction of the “Ghana Gas Infrastructure Project”, a 150,000MMBtu/d processing plant and a 114KM transmission pipeline (Ghana National Gas Company, 2015). Additionally, Quantum Power Ltd and the Ghana National Petroleum Corporation (GNPC) invested US$550million in the construction of a Floating Storage Regasification Unit (FSRU). Also, a total of US$4.9billion was invested into the expansion of the Jubilee Fields and developments of the TEN projects (Tullow plc, 2015). Meanwhile, US$1billion is committed to building a 400MW Bridge Power Liquefied Petroleum Gas (LPG) fired project as indicated on Table 15. In sum, an estimated US$18.5billion is invested in developing the nascent gas industry in Ghana.

Table 15: Total Natural Gas Industry Investments Cost in Ghana

Natural Gas Projects in Ghana	Estimated Investment Cost (US$ billion)
Jubilee Fields	3.15
TEN Project	4.9
Sankofa Gas Project	7.9
Ghana Gas Project	1
FSRU	0.55
LPG Power Plant	1
Total	18.5

Source: Ministry of Finance-Ghana, (2017).

The entire natural gas value chain in Ghana is state-controlled and the private sector argues that the current structure will not be economically and technically efficient for operations since this structure is tied to a debt-ridden electricity sector, which is subject to state inefficiencies. Additionally, inadequate and weak institutional arrangements, lack of a regulatory framework for investments, an inefficient local gas/electricity pricing system, unwillingness to pay and the high risk in infrastructure investments are identified as major problems in developing the nascent gas industry in Ghana.

2.5.1. Natural Gas Supply Outlook in Ghana

Ghana's domestic natural gas supply comes from four confirmed oil and gas projects: Jubilee fields, Greater Jubilee, TEN, SGP and WAGP. Gas production from the Jubilee fields is estimated at 100MMscf/d, TEN is expected to produce 50MMsf/d beginning in 2018 and expected to remain unchanged for six years (Tullow PLC, 2015). SGP is expected to produce at peak of 180MMscf/d of non-associated gas and will remain so beyond 2020. The erratic gas deliveries from Nigeria through the WAGP are between 60MMscf/d and 30MMscfd and prospecting for attaining 120MMscfd contractual deliveries in the future remains uncertain due to gas shortages and infrastructure constraints in Nigeria (World Bank, 2015).

However, an average 30MMscf/d of gas supplies from WAGP is projected, with the potential to be ramped up to 120MMscf/d or more if, for example, all debts accrued are paid. FSRUs are constructed and projected to deliver 250MMscf/d of gas to power 230MW VRA thermal plant (GNPC, 2017). The total expected domestic gas supplies as indicated on Table 16 are estimated to ramp up to about 599MMscf/day in 2020 (World Bank, 2015).

Table 16: Projected Gas Supply in Ghana up to 2020 (MMscf/d)

Natural Gas Supply Sources	2014	2015	2016	2017	2018	2019	2020
Jubilee Fields	-	83	104	104	104	103	98
TEN	-	-	-	-	50	50	50
Sankofa	-	-	-	-	158	171	171
Total of Domestic Production	-	83	104	104	312	324	319
WAGP Imports	30	30	30	30	30	30	30
FSRU-LNG Importation					250	250	250
Total Natural Gas Supply	30	196	134	134	592	604	599

Source: World Bank, (2015).

2.5.2. Natural Gas Demand Outlook in Ghana

Thermal electricity generation capacity currently installed in Ghana stands at 65% of the current generation mix estimated at 2,974.5MW. Sunon Asogli Phase 1 and Asia Middle East Resource Investments (AMERI) IPP are the only "*gas-only*" 360MW and 220MW plants respectively. Other IPPs include Mines Reserve Plant (MRP) (80MW), Tema Thermal 2 Power Plant (TT2PP) (110MW), Kpong Thermal Power Plant (KTPP) (200MW), Sunon Asogoli Phase 2 (180MW) and about 76.5% (1550MW) of the planned capacity of 2025MW are combined cycle gas turbines.

An estimated 2,700MW thermal capacity depends on either gas or LCO as fuel in Ghana. Whilst about 580MW (AMERI and Sunnon Asogli IPP 1) are "*gas only"* plants, total gas demand in the medium term up to 2020 for the "*gas only*" plants is 370MMscf/d. The World Bank (2015) projected a persistent gas supply deficit to 2020 with a maximum deficit of 165MMscf/d in 2017. Therefore, current gas demand requirements in Ghana is estimated at 535MMscf/day (370MMscf/d medium-term demand plus the projected deficit of 165MMscf/d).

Medium-term gas supply is estimated at 599MMscf/day while demand is at 535MMscf/d indicating a 64MMscf/d of gas surplus from 2017. The 64MMscf/d gas surplus projected in the medium term can be committed to developing alternative large-scale consumers and these are sufficient volumes to build an integrated gas-to-fertilizer plant. However, actual gas demand in the medium to long term is projected to increase especially with the coming on stream of the committed thermal plants capacities' gas requirements as feedstock for industries such as fertilizer plants, petrochemical industries, small-scale industrial consumers and other industrial purposes.

The demand for gas in Ghana will outpace supply in the long-run after 2023 when domestic gas production begins to decline. Ghana will probably need to depend extensively on imported gas from Nigeria and LNG or transit to renewable energies for electricity generation. However, due to the intermittency and unreliability of renewable energy supply in providing base-load electricity, the gas industry will continue to be the fuel bedrock of Ghana's energy sector.

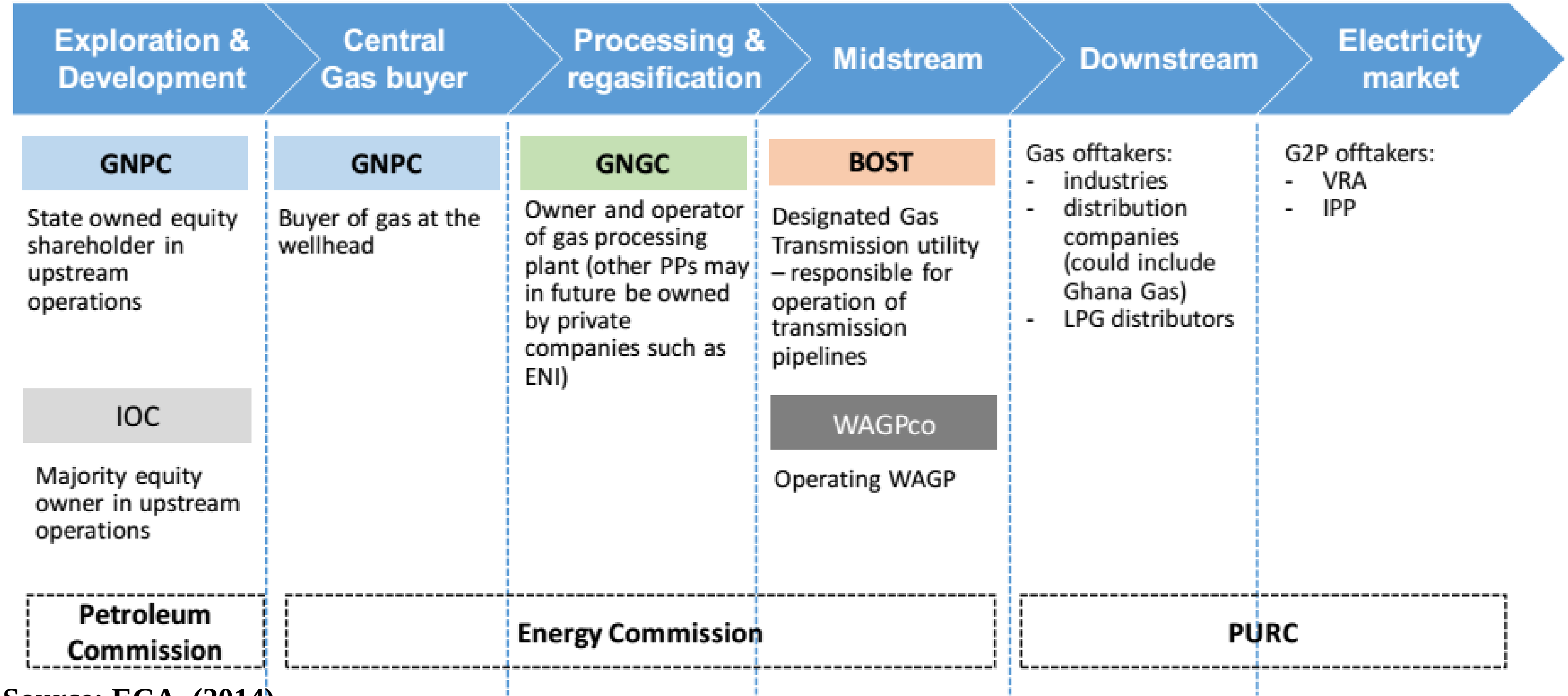
2.5.3. Gas Industry Institutional Arrangements in Ghana

There are several International Oil Companies (IOCs) (Kosmos Energy, Tullow Plc, Anardako, Petro SA, ENI, ExxonMobil, Vitol, and Hess) investing in upstream infrastructure and financing of oil and gas projects in Ghana. Ghana National Petroleum Corporation (GNPC) through joint venture agreement with these IOCs is the National Oil Company (NOC) and upstream gas aggregator.

Public sector players such as the Ministry of Energy is responsible for setting policies, monitoring and oversees all petroleum activities. The Petroleum Commission (PC) is responsible for the regulation of upstream production of oil and gas and grants licenses. The Ghana National Gas Company Limited (GNGC) is incorporated in midstream to build and operate a Gas Processing Plant (GPP) and transmission pipelines and is now a subsidiary of GNPC (Ministry of Energy, 2015). The Energy Commission (EC) is the technical gas infrastructure regulator.

The Bulk Oil Storage and Transportation Company (BOST) is engaged in the transportation and storage of oil and gas. Energy Commission issued BOST the National Gas Transmission Utility (NGTU) License to operate all gas transmission pipelines in an open access and non-discriminatory basis. However, in practice, this is yet to be applied due to regulatory and structural constraints. The Public Utilities and Regulatory Commission (PURC) is the economic/financial regulator of gas, responsible for setting tariffs using the Automatic Tariff Adjustment Formulae, and sets transmission pipeline tariffs. The West African Gas Pipeline Company operates the West African Gas Pipeline to transmit gas from Nigeria to Ghana. Two Independent Power Plants, Sunon Asogli Power Plant and the Takoradi International Company (TICO) are connected to WAGP. Figure 2 indicates both state and private sector and institutional arrangements in the gas industry in Ghana.

Figure 2: Gas Industry Structure and Institutions in Ghana



Source: ECA, (2014).

The private sector sees severe structural constraints in the gas industry, in that, there is a single upstream gas buyer (GNPC), selling to a single downstream buyer (VRA) and restricting participation to state entities i.e. state monopoly. There is lack of regulatory framework for the entire gas industry. There are, too many governmental institutions and regulatory agencies in the gas industry.

2.6.0. Chapter Summary

The development and efficient management of the nascent gas industry will lead to stability in electricity generation and promote a harmonised energy sector, which will propel economic development in Ghana. A stable gas supply condition would promote the industrialisation agenda of Ghana. With a stable energy sector, reliable and cheap electricity, the Ghanaian economy is likely to return to its usual growth rates and sustained development. This, in effect, will lead to the realisation of the long-term aim of attaining a higher middle-income country status in Ghana.

CHAPTER THREE
LITERATURE REVIEW

3.0. Introduction

Chapter three (3) focuses on the review of literature relating to the development of the nascent gas industry in Ghana. This chapter is divided into three main parts. The first section discusses the theoretical literature and the second section, the empirical literature. The final section discusses the three strands of the study, which relate to the three study objectives.

3.1.0. Theoretical Underpinning of the Study

In recent times, attempts have been made to define the relationship between industry structure, regulation and infrastructure investment decisions in the gas industry, especially with the current debates on market liberalisation. These have led to scholars relying on various theories to help explain current occurrences such as the Structure-Conduct-Performance (SCP) paradigm and the Transaction Cost Economics (TCE) theory.

3.1.1. Structure-Conduct-Performance Paradigm and the Gas Industry

The Structure-Conduct-Performance paradigm is designed to analyse and contextualise the competitive condition of industries by examining how the underlying structure (the factors that determine market competitiveness) of an industry are related to and affects the conduct (behaviour) and performance of firms (Bain, 1956; Klint and Sjoberg, 2003). SCP emphasises the interrelation between industry structure, regulation and performance (Panagiotou, 2006; Matyjas, 2014).

The SCP paradigm states that market structure and the number and relative sizes of firms in an industry drive conduct like output decisions and pricing behaviour. Such firm conducts subsequently yield an industry overall economic performance such as efficiency and profitability (Spanjer, 2009; Panagiotou, 2013). The SCP framework supports policies for structuring industries in developing competitive markets (Panagiotou, 2006; Akher and Barcellors, 2013). There is a strong connection between investment decisions, regulation and structure (Klint and Sjoberg, 2003). Moreover, there is a stable and casual relationship between industry structure[7], regulations[8] and investments. In essence, once industry structure is determined, regulations can be defined, which, in turn stimulates investments decisions (Panagiotou, 2006).

Slaba (2008) employed the SCP model to analyse the liberalisation of European Union natural gas markets vision versus its realities. The gas industry exhibits features of market failure in scope and scale economies, inspiring the application of the theory of natural monopoly. Vertical integration (VI) of gas companies was considered the optimal gas market structure to enable the realisation of scope economies. The traditional VI are contested due to their ineffectiveness and suggestions were made for liberalised structures.

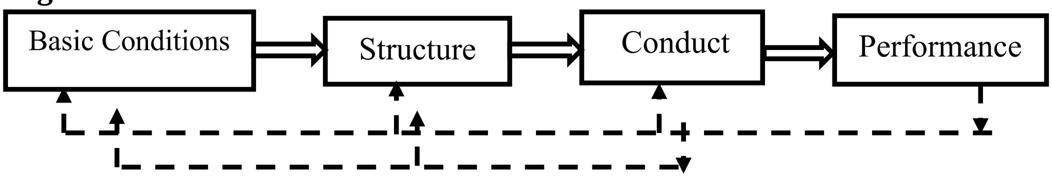
[7] Industry structure is described as the total number of buyers and sellers, degree of vertical integration, homogeneity of the products, and the cost components in a particular industry (Klint and Sjobert, 2003).

[8] Regulation means government impose control on particular aspect of business related to economic regulations which includes control over tariff structure, quality of service standards, access conditions to networks, entry and exit conditions for participants and investment obligations relative to existing and new costumers (Gencer et al., 2006).

To introduce new market structures such as competition, there was the need to change market regulations and industry performance. Among the reform suggestions were laws to break the monopoly in the commercial activities of gas supply and imports and enforce third party access to gas networks.

The SCP paradigm is used by Slaba (2008) to explain the on-going occurrences in the gas sector reforms as basic conditions in the gas market influence market structure. Basic conditions and market structure influence the conduct of market players; thus, further determining sector performance. The consequences run in the reverse (performance influences market structure and conduct) as indicated on Figure 3.

Figure 3: Basic scheme of the Structure-Conduct-Performance Model



Source: Slaba (2008).

The basic conditions are related to regulations and the economic framework within which the gas industry operates (vertical integration or competition). Gradually, the gas market is opened and gas customers are eligible to choose gas suppliers. There is a fair access to competing infrastructure subject to regulations and support for infrastructure integration. In addition, there are independent regulatory bodies to harmonise and supervise fair access to infrastructure and transparent setting of access tariffs.

Market structure is the number and size of firms in the industry, i.e. market concentration. This relates to unbundled network operators, new gas suppliers, shippers, traders' ability to enter the market, a decrease in concentration of one national company, customer's eligibility to choose suppliers and the independent regulatory body with sufficient competencies. With Conduct, network operators compete for gas suppliers and invest in new interconnections, secure fair Third Party Access (TPA), diversify gas sources and transport routes and customers are able to choose suppliers with suitable products, services and prices. There are, also, harmonised and effective network access regulations and price setting.

Industry performance, on the other hand, relates to the objectives set for the industry: effective competition in gas supply, lower gas prices, higher quality and diversity of services and products offered, higher security of supply, transparent network tariffs, fair access to network and effective competition in the area of network. Peng and Poudineh (2015) developed an analytical framework based on the Structure-Conduct-Performance-Regulation (SCPR) paradigm, which aligns the interconnection of gas-to-power development in the UK for thorough identification and discussion of sector structure, infrastructure, market and regulatory drivers. Two structures in the gas-to-power industry were identified: complete centralisation and decentralisation.

Centralisation involves the state-owned vertical integration where a state entity controls gas production, imports/exports, assets and downstream consumption. In contrast, complete decentralisation, involves all non-networks such as production, imports/exports, storage and power generation segments opened to competition by several participants whilst, transmission and distribution networks are owned by regulated monopolies. The regulatory bodies include the ministry concerned and a regulatory authority more or less independent from the ministry.

The regulatory authority is responsible for the day-to-day monitoring of the structure of the industry ensuring that it is perfectly decentralised to promote competition, coordination occurring within markets especially ensuring cost recovery, promoting investments, and ensuring that governments and investor expectations are met.

Infrastructure Investments recognised that domestic gas/power production generates higher risk and to proceed with infrastructure investment requires cost recovery for network investments integrated into the overall gas/electricity tariff payable by end-users. Three lessons are learned from the use of the SCP in interrelated gas-to-power studies. Firstly, Gas-to-power is an interdependent environment and any weak link can cancel out performance improvements in other segments. Secondly, liberalisation is not an end but a means to increase operational efficiency and investments in infrastructure development. Finally, political conditions greatly influence the energy policy of a country, including the natural gas industry policy.

The SCP framework confirms the interaction between industry structure, regulations and infrastructure investments in the gas-to-power sector development. The SCP framework is not a fully specified theory but its value lies in establishing the interaction of structure, regulations and investments in the gas industry (Peng and Poundineh, 2017). SCP paradigm is built on loose theory, described as a less analytical and a more descriptive theory (Lopez, 1999; Maskin and Tirole, 1988).

3.1.2. Transaction Cost Economics and the Natural Gas Industry

A New Institutional Economics Theory, Transaction Cost Economics (TCE) gives importance to transactions and institutions that govern the performance of industries (Coase, 1937; Coase 1988; Williamson, 1992; Buchanan, 2001). A transaction is said to take place whenever a good or service passes from one party to another (Coase, 1937; Williamson, 2010). TCE takes a broader perspective to determine the performance of an industry considering the institutional environment and regulatory governance (Williamson, 2000).

The most powerful extension and development of TCE[9] has been that of Williamson (1975, 1986, 1996, 2007 and 2010). TCE has been extensively used for analysis of vertical integration decisions, networks and governance forms in the natural gas industry and to provide understanding of the structure, conduct and performance of transmission networks (Martins et al., 2010; Glachant et al., 2014; von Hirshhausen et al., 2012; Arora, 2012). TCE provides both theoretical and dynamic context of institutional specifics, framework of analysis and regulatory actions for the natural gas industry (Correlje and Groenewegena, 2006). TCE is an empirical success story (Williamson, 1996) and seems to be

[9] Correlje and Groenewegena (2006) describe transaction cost to include the direct cost of writing, monitoring and enforcing contracts, plus the costs associated with the risk if ex ante investments having an ex post performance that is lower than anticipated, as a consequence of contractual hazards of various types and of the cost associated with internal organisation of the transaction.

the most suitable theoretical framework for analysing the natural gas industry (Arora, 2012; Crocker and Masten, 1996; Williansom, 2005).

Williamson (1981; 2007) identified three basic units of TCE: asset specificity, uncertainty and frequency of transactions responsive to bounded rationality and opportunism as explained on Table 17. Asset specificity, uncertainty, and frequency of transactions are the main drivers influencing the extent of transaction cost in the gas industry (Williamson, 1998; Ruster and Newmann, 2006). Williamson (2011) posited that, under the conditions that the assumptions hold, asset specificity, uncertainty and frequency determines what kind of transaction cost would be generated. When a transaction cost will be carried out in a market and if an asset is very specific to a particular transaction and has almost zero opportunity cost, then it is efficient to vertically integrate.

Table 17: Transaction Cost Attributes and Description

TCE Attributes	Description
Asset Specificity	Refers to the extent to which assets are specialised to a specific transaction and can be used only at lower value to the alternative application. Or these are durable investments that are undertaken in support of a particular transaction, the opportunity cost of which investment is much lower in best alternative uses or by alternative users should the original transaction be prematurely terminated. These assets cannot be redeployed to alternative uses without loss of productive value. Example; physical, human, site specific, dedicated, brand name, capital, and temporal (episodic) forms.
Uncertainty	Information about the past, current and future states is not perfectly known for various reasons. Uncertainty arises from not knowing about future states or/and the ability to determine who is more prone to behave opportunistically.
Bounded rationality	Relates to behaviour that is intendedly rational but only limitedly so; which is protected through vertical integration.
Opportunism	When individuals (companies) seek self-interest with guile, fragility of motive and these activities are both subtly and overtly deceitful ex ante and ex post to agreeing on contracts. The incompleteness of contracts attracts opportunism and were it not for opportunism all behaviour could be rule governed. Without opportunistic behaviour, contracts would have been costless enforced and there would be no reason for other forms of economic organisations.
Frequency of transactions	A larger frequency or larger volumes of transactions, gives rise to justification for alternative governance structures and the degree of frequency should range from occasional to recurrent.

Source: Adapted from Williamson (2010); Spanjer (2009).

3.1.3. The TCE Framework

The concept of TCE is adapted for the study of the nascent gas industry in Ghana in understanding why a particular industry structure, regulatory governance arrangement and infrastructure investments decisions are considered. TCE allows the identification of the most economically efficient governance structure[10] based on regulatory arrangements and investments attributes (Williamson 1979). Williamson noted that, a simple governance structure should be used for simple transactions and complex governance

[10] Governance structure: is the institutional matrix within which transactions are negotiated and executed which varies with the nature of transactions (Williamson, 1979)

structures should be used for complex transactions. The use of complex structures for simple transactions incurs unwanted cost and the use of a simple structure, for complex transactions results in a strain. The three most important characteristics of TCE are asset specificity, uncertainty and frequency of transactions and their interaction determines the governance structure and regulatory arrangements in the industry.

Gas transactions are asset specific and cannot be redeployed without losing value, and when a buyer and seller enters into a transaction, the suppliers are effectively "locked-into" that specific transaction to a significant degree. The buyer, thus, cannot turn to alternative suppliers to obtain the product on more favourable terms since the cost of supply from unspecified sources is considered great (Williamson, 1979) and the buyer is "locked-in" (committed to) the transaction.

Transaction idiosyncrasies evolved between the buyer and seller in cost savings, economics of scale and scope. Specialised language develops as communication and experiences are accumulated. As nuances are signalled and received in a sensitive way, institutional and personal trust relations evolve. These idiosyncratic relationships are transformed into bilateral monopoly relationships. Frequent spot trading is possible when these transactions become standardised. By assumption, cost economies in production are realised in these idiosyncratic relationships only if the supplier invests in special purpose plants and equipment or if labour develops transaction specific skills in the course of the contract execution. The assurance of continuous transactions from both parties encourages investments (Williamson, 1979).

These bilateral relationships result in long-term contracts, which are considered incomplete due to bounded rationality. Maintaining consistency poses challenges, which may require appropriate specified state-contingencies in regulations though the absence of the hazard of opportunism would have eliminated the difficulties through faultless adaptation of sequence by both parties (Williamson, 1979). Given, however, the unenforceability of terms in these long-term contracts and bilateral monopoly transactions efficient adaptation, options are given to both contracting parties to benefit from incremental gains outside the contracts to prevent self-interest seeking and opportunism. Therefore, governance structures that provide these flexibilities are needed (Willaimson, 1979).

In developing alternative governance structures, it is important to consider the cost economisation of these transactions, and this essentially takes two forms: economising production expenses and economising transaction costs (Williamson, 1979). To the extent that transaction costs are negligible buying (competition) rather than self-production, vertical integration is the most cost effective means of procurement to benefit from economies of scale and ensure collective pooling and full-realisation of resources. A shift in one governance structure to another is likely to result in challenges. Figure 4 indicates the two-three matrix, which describes the six types of transactions to which governance structures are matched.

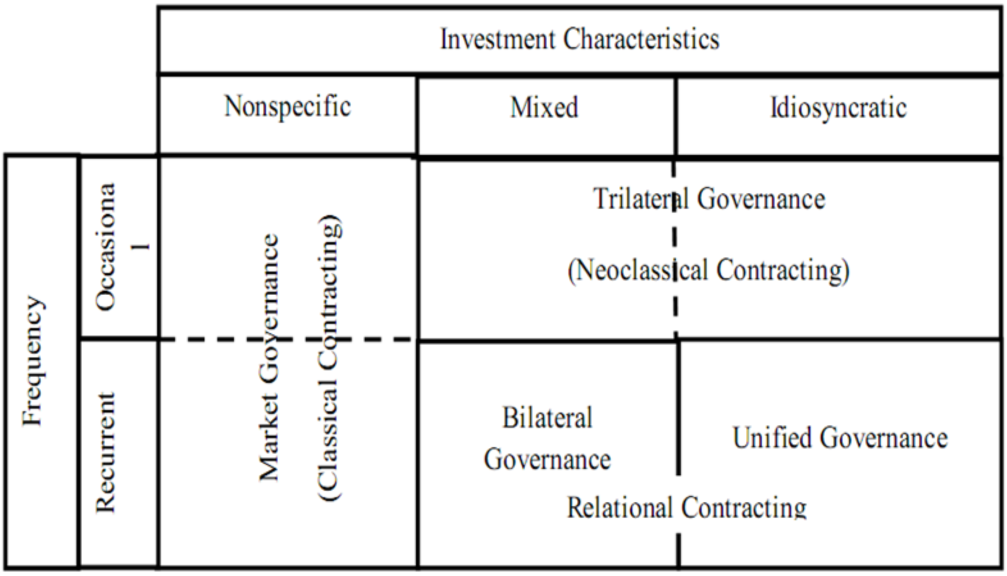
On governance structures: three structures are considered: non-transaction specific, semi-specific and highly specific. For the non-specific, faceless buyers and sellers meet for instant exchange of standardised goods and services at equilibrium prices and by contrast, highly specified structures are tailored to the special needs of the transactions. The semi-structured fall in between (Williamson, 1979) and several propositions are drawn:

1. Highly standardised transactions do not require specialised governance structures.
2. Only recurrent transactions will support highly specialised governance structures.
3. Occasional transactions of a non-standardised kind will not support transaction specific governance structures and require attention.

In the absence of standardised markets, the parties can design alternative patterns of future relationships based on different governance arrangements. The assumption is that recurrent and discrete transactions are well suited for more competitive market structures. Different governance structures are what protects each party against the opportunism of the opposite party (Williamson, 1979).

The investments characteristics (nonspecific, mixed and idiosyncratic) of transactions in the gas industry will determine the type of structures and regulations to use. For instance, in trilateral governance structures, there are occasional transactions to mix to a highly idiosyncratic kind. Once parties enter into contracts in such structures, there are strong incentives to see such contracts through to completion.

Figure 4: Basic scheme of the TCE Framework



Source: Adapted from Williamson (1979).

Special investments are kept in place in case the opportunity cost is lower in alternative uses and transfers to others causes inordinate difficulties. Transactions conducted under certainty are relatively easy to manage except when there are time differences in reaching their equilibrium; any governance structure is suitable. The uncertainty of intermediate or high degree is relevant in transactions, as occasional and nonstandard transactions are considered significant in access uncertainty. Bilateral governance structures will need to give way for unified structures as uncertainty increases for recurrent transactions (Williamson, 1979).

On regulations, special governance structures are needed to the degree efficient supply is necessary to maintain transactions between buyers and sellers in a continuous bilateral relation. The reasons for regulations are to:

1. Protect the interest of prospective parties and
2. Adapt the relationship to changing circumstances.

Regulations are mostly needed when the governance structure adapted has more natural monopoly features to protect investors (sellers) and buyers' security of expectations provide adaptive sequential decision-making processes (Willaimson, 1979). In addition, Rate-of-return regulations have these periodic review features.

The TCE framework for the gas industry as adapted from Williamson (1979; 1995) has two complementary parts: first, dealing with background conditions of industry development in Ghana and the second, with governance mechanisms. The institutional environment is the set of fundamental, political, social and legal ground rules that establish the basis for production, exchange and distribution activities of gas. Institutional arrangements between economic units that govern the ways in which these units can corporate and/or compete provide a structure within which its members can corporate or a mechanism that can effect change in laws and property rights (Williamson, 1995).

This is usually a bottom-up approach to economic organisation, where the interest of individual firms in the industry influences the institutional structures and governance arrangements in the gas industry. Individual firms, the governance structure and the institutional environment relate to each other as shown on Figure 5. The solid arrows show the main effects and the dashed arrows show the feedback effects.

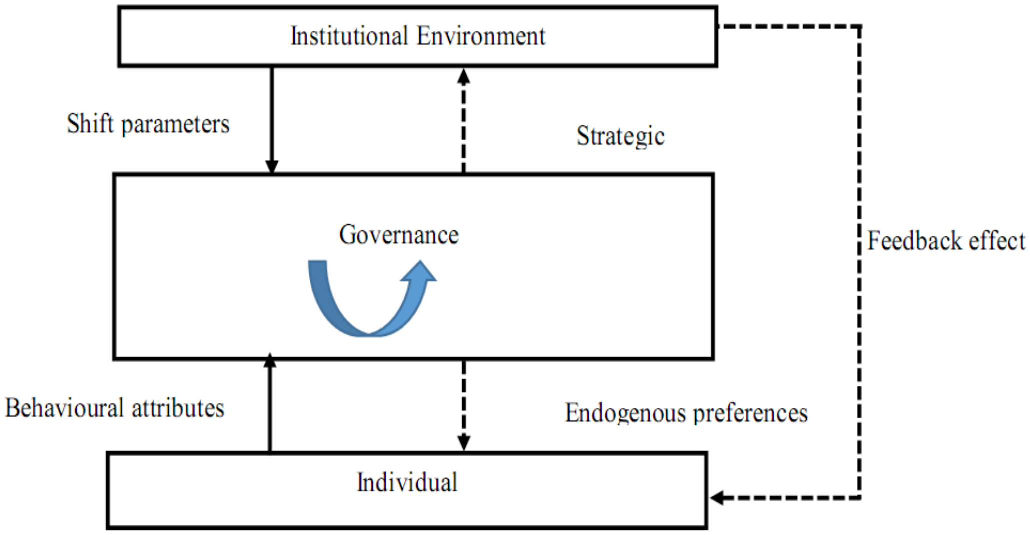
The institutional environment comprises of the rules of the game as a vital component of the gas industry. It is easy to assign too much weight to the institutional environment and too little to the institutions of governance. TCE also concerns regulations and it is an interdisciplinary undertaking that joins law, economics and organisation.

The law defines the rules of the game; organisational theories are implicated in behavioural assumptions and relates to the behaviour of organisations. Organisations have a life of their own and undergo inter-temporal transformations that need to be identified and factored into the analysis. Economics provides the core logic, in that, the analysis works out of the "rational spirit" and the objective is to examine "incomplete" contracts in their entirety (Williamson, 1995).

The individual firm: the pressing need for the individuals are to be described in workable realistic terms and bounded rationally, where the firms seek their own interest with guile and fragility of motive and reason, which TCE terms as opportunism. The firms in the gas industry seek profit motives. TCE avers that there are different dimensions of frequency with which transactions recur, the uncertainties they are subject to, the degree of asset specificity and the ease of measurements. These are important to the governance of contractual relationships (Williamson, 1995).

The performance of these individual firms send a feedback signal to the institutional environment to inform the governance structure to adopt. TCE is always and everywhere a comparative institutional analysis, comparing two or more feasible forms of governance structures (Willaimson, 1995). TCE is more microanalytical, self-conscious of behavioural assumptions, introduces the economic importance of asset specificity, regards the firms as a governance structure rather than a production function and places more weight on ex post institutions of contracts.

Figure 5: Basic scheme of the TCE Framework



Source: Adapted from Williamson (1979).

Ex post,[11] safeguards can take several forms of which the most obvious is common ownership. If faced with difficulties from contracting parties, this may be substituted for the internal organisation of the market. Ex ante safeguards, as well, can be fashioned to signal credible commitments and restore integrity to transactions (Willaimson, 1985). Further, Klein (1999) observed that the probability of observing a more integrated governance structure

[11] Ex post cost contracting include: the maladaptation cost incurred when transactions draft out of alignment in relations to the 'shifting contract curve'; the haggling cost incurred if bilateral efforts are made to correct ex post misalignment; the set up and running cost associate with governance structures to which disputes are referred and the bonding cost of effecting secure commitments (Williamson, 1985)

depends positively on the amount or value of the relationship-specific assets involved. These include the significant levels of asset specificity, the degree of uncertainty about the future of the relationship, the complexity of the transaction and the frequency of trade. In this instance, governance structure is the dependent variable whilst asset specificity, uncertainty, complexity and frequency are the independent variables.

Investment hold-up or investment obstruction relates to relationship-specific investments (Klein, 1999). This is where the investor is tied to a specific transaction with limited options into the near future, which is the best-known example of an ex-post contractual hazard (Spanjer, 2009). A governance structure capable of eliminating this investment hold-up problem is vertical or lateral integration (Klein, 1999; Spanjer, 2009). Less extreme governance structures include long-term contracting, partial ownership agreements for both parties to invest in offsetting relationship-specific investments and several other governance structures may be applied (Klein, 1999).

TCE holds that parties tend to choose the governance structure that best controls underinvestment and protect their relationship-specific investments at least-cost given the particulars of the interactions (Klein, 1999). And the preferable arrangements of governance structures are those that best fit the character of the transactions involved and the broader context in which they take place (CIEP, 2006) such as the extent to which parties are lock-in as a consequence of asset specificity.

The interplay of regulation with investments, irreversibility, uncertainty and risk determines whether a regulatory regime will create a governance structure that will sufficiently attract investments (Spanjer, 2009). The choice between competitive and integrated structures are influenced by these interplays. TCE takes into account ex-post adaptation problems and potential inefficiencies in ex ante investments risk, which provides a comparative institutional choice approach in analysing alternative governance arrangements (Joskow, 2010).

Gas network infrastructures are dedicated and site-specific assets and because of the existence of economics of scope and scale, they are considered common pool resources[12] (Hallack and Vazguez, 2014). The use of these infrastructures raises challenges on how to coordinate different users. Allowing third party access to these infrastructures can enable redeployeability of access capacity (Ruster and Newmann, 2006), as these infrastructures such as transmission pipelines and FSRUs are excludable[13] and subtractable[14] (Hallack and Vazguez, 2014).

The characteristics of network infrastructure in the gas industry are a source of severe transaction cost (Hallack and Vazguez, 2014). TCE is used to deploy efficient market regulations. The risk attributes of specific infrastructure investments and the ex post risk profile of different markets may suggest the

[12] Common pool resource theory is applied to understanding of natural gas networks which explains the use of the same infrastructure by different users (Hallack and Vazguez, 2014).
[13] Excludable: as it is physically relatively easy to exclude individuals to use gas infrastructure
[14] Subtractible: As the use of gas, network infrastructure decreases the available capacity (Hallack and Vazguez, 2014).

use of a mix regulatory approach and competitive policy (Correlje and Groenewegen, 2006).

Arora (2012) stated that, the TCE approach seems more applicable to the gas industry as compared to Agency theory or the property rights theory. TCE provides a comprehensive theoretical underpinning for institutional analysis, the determination of firm boundaries as well as the interrelation of industry structure, regulatory framework and governance arrangements in the gas chain analysis (Joskow, 2000; Tadelis and Williamson, 2010). The TCE framework is adapted for this study and seen an appropriate theoretical basis for the analysis of investment and risk decisions, analysis of network operations, setting open access rules, coordination of industry structures and regulatory governance in the nascent gas industry in Ghana.

3.2.0. Empirical Review of the Development of Gas Industries

The empirical review is structured into three sections: the first section considers gas industry development experiences from developed countries' perspective; the second, from the African countries' perspective and the final section, Ghana. The purpose of the empirical review is to:

- Supplement the theoretical review with evidence from the gas industry;
- Help identify the methodological trends and to select the most appropriate research methods (sampling, data collection and analytical techniques) and
- Guide the drawing of sound conclusions for the present study.

3.2.1. Gas Industry Development: Developed Countries Perspectives

This section reviews empirical literature of the integrated studies of structural, regulatory and infrastructure investment decisions of the gas industry from developed countries' perspectives. von Hirschausen (2008) and Peng and Poundineh (2015) recognised the need for integrated studies between restructuring, regulations, infrastructure investment decisions and supply security in the gas industry to provide a holistic framework analysis for USA and UK gas industries respectively.

Structurally[15], in the past 25years (see Box 1 & 2), the developed world witnessed the gas industry go through series of liberalisation in breaking-up monopolistic, vertically integrated structures into competitive markets and the introduction of sector-specific regulations. State-controlled utilities were used to facilitate the necessary investments in the industry (Spanjer, 2008). However, monopolistic structures, over time, lost their purpose so the industry was deregulated[16]. Some segments (production/supply and consumption) were open to competition whilst transmission and distribution sectors were maintained as a monopoly subjected to regulation (Andrade, 2014).

Aguilera et al. (2014) succinctly capture the structural arrangements of the developed gas industries saying North America has a relatively highly

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[15] The objective of structural change in the energy sector is to allow competition in production, services and retail segments and regulate essential facilities (Correlje and Groenewegen, 2006).
[16] Deregulation was typically the separation of potentially competitive segments from, the characteristic segments of natural monopoly which continue to be subjected to regulatory mechanism (Andrade, 2014)

competitive market structure while Europe is better described as more oligopolistic with considerable state participation at all the stages of the supply chain. The Asia Pacific is only slowly evolving from a structure of several bilateral monopolies to competition.

Box 1: The North American Liberalised Gas Markets

US wellhead gas price regulation was passed in 1954 with a Supreme court Philip Decision, which implies that gas destined for interstate consumption would be produced at government-determined prices. Other important orders are:
US (1984) – FERC order 380: removed contractual minimum bill obligation. The pipeline companies had long-term sales contracts with a minimum bill obligation.
Canada (1985) – Agreement on gas market (Halloween Agreement) prices, deregulation of gas prices.
US (1985) – FERC order 436: allowed pipeline companies on a voluntary basis to offer transportation services to customers. Prices were partially deregulated, natural gas spot markets developed.
US (1992) – FERC order 636: required pipelines to separate their sales services from their transportation services and provide all transportation on an equal basis for all gas suppliers. Transportation remained a regulated monopoly but sales were opened to competition. This is the most significant single instrument in the market opening process.
Source: IEA (2008).

Box 2: European Union Natural Gas Liberalisation Process

The main aim of liberalising the European gas industry was to create a more appropriate competitive framework in gas-to-gas competition, increase economic efficiency and lower the cost to final consumers.
This resulted in the first Gas Directive (98/30/EC) aimed at providing a new gas legal framework for opening the gas networks to third parties. This was to be achieved through unbundling of the vertically integrated gas operators, thus allowing competition for suppliers and consumers within the natural monopoly network.
A new Gas Directive (2003/55/EC) adopted mandated Third Party Access (TPA) as the basic rule for all existing infrastructure, as well as moving the level of unbundling of the Transmission System Operator to the level of legal separation. In addition, the role of independent regulators was enforced.
Third Order: The rationale is the integration of the energy and the environmental objective of EU with market-based and other measures. The main features of the third package consist of internal industry structural change namely ownership unbundling, network harmonisation, continuous identification of missing infrastructure, increased coordination between Transmission System Operator and regulators through existing institutional groups.
Source: IEA (2008).

It emerged that efficient adoption of a specific structure may be as a result of the nature, maturity and risk profile of the industry that require full competition, definition of access rules and tariff regulations. Opening the upstream and downstream markets to competition favours infrastructure investments (von Hirschausen, 2008), and every structure adopted has its regulatory design (Spanjer, 2009).

Regulations and governance arrangements: the natural monopoly segments (transmission and distribution) are subjected to regulation. Regulation is seen as a corrective measure of market failure (Spanjer, 2008). The main objective of regulation is to avoid monopoly inefficiency in gas transmission and distribution and protect consumers from exploitation (Andrade, 2014).

How can the regulatory framework establish a workable balance between appropriate industry structure and infrastructure investments decisions? Incentive regulations are considered to have significant impacts on higher infrastructure investments compared to rate-of-return regulation (Correlje and Groenewegen, 2006; Andrade, 2014). For governance arrangements, the regulator should be able to operate effectively with a clear politically determined legislative mandate and objective to develop guidelines and rules. They should be able to operate independently and balance the interest of all stakeholders' across all the segments of the gas industry. An appropriate regulatory framework is the most effective instrument for attracting infrastructure investments (von Hirschausen et al., 2004).

Infrastructure Investment Decisions: the shifts towards liberalisation and its complementary regulatory system come with uncertainties in investment. The main concern here is how to attract and sustain infrastructure investments, as investments are required along the entire natural gas value chain (exploration and production, transmission, distribution and ancillary services).

Regulation is the most important determinant of infrastructure investment decisions in the gas industry (von Hirchausen, 2004). Therefore, issues of Third Party Access to essential facilities must be sufficiently resolved by the regulatory framework (Weijermars, 2010). Infrastructure regulations are subject to cost-of-service (Rate-of-return) regulation. Relying on traditional regulatory systems to set competitive prices may lead to adverse effects on innovation and new investments (von Hirschausen, 2008).

Rate-of-return regulation is widely criticised for overinvestments (Averch and Johnson effects) or inefficiency. Price cap regulations are considered a reactive measure to the inefficiencies (von Hirschausen et al., 2004). Cost-plus and incentive-based regulations continue to go hand-in-hand leading to workable hybrid forms of regulations such as sliding scale (von Hirschausen et al., 2004).

The main issue in the design of industry structures and regulatory arrangements is how to align business responsibilities of the players. The interplay of regulation with investments, irreversibility, risks and uncertainty determines whether a regulatory regime will create a governance structure that sufficiently facilitates investments (Spanjer, 2009). Uncertainty/risk lowers investments both in the short and long-run (Spanjer, 2009) and requires management (Weijermars, 2010).

Talus (2014) related to the divergence in the Asia-Pacific natural gas industry. Long-distance LNG trades, linked to crude-oil indexation, take-or-pay contracts with destination clauses, absence of short-term trades and higher prices, mark these markets. State-controlled companies, limited third-party access to pipelines and other infrastructure dominate the Asian gas industries and government regulated gas prices (Vivoda, 2014). Aguilera et al. (2014) identified several obstacles limiting the development of the Asian gas markets: limited gas delivery infrastructure, lack of storage facilities, underdeveloped or inflexible markets and limited legal and regulatory frameworks.

In sum, it is well established from the developed countries' gas industries perspective as indicated on Table 18, that integrated studies of the structure, regulations and investments decisions are relevant to provide detail analysis of the gas industry and the lessons learned are:

- The literature review reveals that there are increasing studies of integrating structure, regulation and infrastructure investments decisions in these gas industries.
- There are attempts to transit from monopolistic, vertically integrated, and state control structures towards competitive structures.
- Appropriate and effective regulatory framework for the gas industry affects the level of infrastructure investments.

The basic conditions required for the development of a nascent gas industry from the literature review and lessons from the developed countries perspective is to develop integrated studies of the structure, regulations and infrastructure investments decisions.

Table 18: The Gas Industry from Developed Countries Perspectives

Reference	Sector	Definition of Sector Performance	Analytical Methods	Main findings & recommendation
von Hirschhausen (2008)	Natural Gas/Utilities	Infrastructure, regulations, investments and security of supply of the restructured USA natural gas industry.	Literature review and case studies	*Main finding*: there is a relationship between regulatory framework and infrastructure investment. There is little reason for concern about infrastructure investment, resource adequacy and security of supply.
Peng and Poundineh (2015)	Natural Gas and Electricity	Gas-to-power development in the UK.	Analytical framework based on Structure-Conduct-Performance-Regulation paradigm and System Dynamics.	*Main finding:* a holistic framework for the identification and discussion of power and gas sector structure, infrastructure, markets and regulatory drivers. *Recommendation:* There is an interconnection between gas-to-power structures, regulations and infrastructure investment.
Juris (1998)	Natural Gas	The emergence of markets in the natural gas industry.	World Bank records and experiences from natural gas industry stakeholders.	*Main Finding:* Deregulation in the natural gas industry leading to increasing competition benefiting everyone through efficient pricing and greater choices in natural gas contracts. Four distinct restructuring models are identified: vertical integration, competition, open access and unbundling. Regulation was identified equally important in maintaining the structure. *Recommendation:* These structural and regulatory reforms are available to nascent gas industries trying to develop their gas markets.
von Hirschhausen, et al., (2004)	Utilities	Infrastructure regulation and investment for the long-term.	Literature review and case studies	*Main findings*: appropriate regulations are required to sustain long-term investments. Structural constellations are as well required in state ownership, regulated and unregulated private ownership in long-term investment decisions.

Continuation

Joskow (2005)	Electricity and Natural Gas	Supply security in competitive electricity and natural gas markets.	Literature review and case studies	*Main findings*: there is a growing link between electricity and gas sectors. *Recommendations*: industry structures, regulations and reliability policies are needed to be compatible across both industries.
Neumann and von Hirschhausen (2006)	Natural Gas	Long-term Contracts and Asset Specificity: an empirical analysis of producer-importer relationship in the natural gas industry.	Quantitative Method and interviews	*Main findings*: Contract duration decreases as the market structure of an industry develops into competitive structures. Contracts that are linked to an asset-specific investment are on average four years longer than those that are not. Long-term contracts are considered instruments to over-come hold-up problems.
Correlje and Groenewegen (2006)	Natural Gas	The gas market, transaction costs and efficient regulations in EU.	Literature Review	*Main Findings:* Regulation has a strong impact on market development but it is not the driving force for market design. *Recommendation*: the use of mix regulatory approaches and competition policy instead of a single market design for efficient regulatory design.
Spanjer (2009)	Natural Gas	Structural and Regulatory reform of the European natural gas market.	Literature Review and Case Studies	*Main findings*: TCE is the proper theoretical base for gas regulation. *Recommendation*: European natural gas regulation should move from its neoclassical regulation to TCE.
Dong et al., (2017)	Natural Gas	The reform of natural gas in the PR of China.	Literature review	*Main findings*: China gas industry is challenged with lack of top-level design of gas policy, ineffective industry supervision, and imperfect natural gas pricing mechanisms. *Recommendation*: full natural gas industry reforms should be conducted and encouraged to help unveil the problems and challenges of the gas industry reform process. It will help formulate suitable measures for effective natural gas reform.

Continuation

Andrade (2014).	Natural Gas	The impact of regulation, privatisation and competition on gas infrastructure.	Quantitative Analysis	*Main findings*: privatisation has a strong impact on investments. Different forms of regulation seem to have an important role in transmission investments. Incentive regulation has a positive impact leading to higher investment more than the rate of return regulations.
Weijermars (2010)	Natural Gas	Value chain analysis of the natural gas industry – Lessons from US regulatory success and opportunities for Europe.	Literature review and case studies	*Main findings*: it is essential to remove impediments in the natural gas value chain and streamline the decision-making process. *Recommendation:* increase liquidity in natural gas markets by enforcing Third Party Access pipeline. Provide incentive regulations to increase market liquidity. Provide higher Rate-Of-Return in the authorised Weight Average Cost of Capital for new infrastructure investments to stimulate timely delivery of energy projects.
Weijermars (2012)	Natural Gas	Regulatory reform options to revitalise the US natural gas value chain.	Literature review and case studies	*Main findings*: Revised rate-making is required to improve the regulatory horizon of utilities that compete for access to funds from capital markets. *Recommendations*: True cost of capital should be allowed in rate cases under the General Rate Case and Cost of Capital Mechanism. Construction Work In Progress (CWIP) inclusion in the rate base and quick approvals of new project investments are essential for successful fundraising. Allow for lower debt to equity ratios, which will reduce financing cost for the utility industry.
Songhurst (2017)	Natural Gas	The outlook for Floating Storage and Regasification Units (FSRU).	SWOT Analysis	*Main Findings*: FSRU businesses has grown rapidly. The FSRUs are reusable assets. Majority of the current FSRUs are linked to smaller onshore power plants. By offering low cost, fast track and flexible option compared to onshore terminals, FSRU offers an excellent opportunity to grow the LNG market internationally. The possibility of developing Floating Power Generating Units (FPGU). *Recommendations*: FSRUs can be used to offer a complete gas-to-power package with a power generation facility either on the FSRU or adjacent ship barge or onshore

Continuation

Talus (2014).	Natural Gas	United States natural gas markets, contracts and risks: what lessons for the European Union and Asia-Pacific natural gas markets?	Comparative methodology and literature review	*Main Finding*: Long-term contracts provided predictability over long periods, the companies involved could plan their infrastructure needs with a high degree of certainty. Long-term contracts allow for the financing of large-scale infrastructure projects through project financing. *Recommendations*: regulatory frameworks, industry structure and infrastructure investments should be adapted to reflect the needs of the particular natural gas industry.
Vivoda (2014)	Natural Gas	Natural gas in Asia: Trade, markets and regional institutions.	Literature review and case studies	*Main Findings*: LNG prices in Asia are benchmarked against the average monthly price of crude oil imports. State-owned companies with limited competition dominate domestic gas markets in Asia. Security of supply policy is the primary objective for most Asia LNG trades. The role of the state as a market participant instead of regulator through vertical integrated gas companies limits competition and market efficiency. *Recommendations*: LNG prices should be de-linked from crude oil prices and move towards a mixture of pricing approaches: hybrid oil/coal/Henry Hub indexation and potential regional hub indexation
Aguilera et al., (2014)	Natural Gas	The Asia Pacific natural gas market: Large enough for all?	Analytical framework	*Main Findings*: Natural gas will play a significant role meeting Asia energy demand. Asia gas industry may see a shift from oil-based pricing to gas-on-gas pricing regime, with hub-based pricing in China. *Recommendation*: provide understanding of the evolution of the market structure and pricing mechanisms in Asian gas market will be important.

3.2.2. Gas Industry Development from African Perspective

Africa holds about 503.3TCF of global proven natural gas reserves, 7.3% of all world reserves (BP statistical review, 2017). These proved gas reserves are highly concentrated in four countries – Nigeria, Algeria, Egypt and Libya accounting for more than 92% of total reserves (E &Y, 2013). Africa produced 208.3BCF of gas in 2016 led by Algeria, Egypt, Libya and Nigeria collectively accounting for 88% of production. Production growth rate in Africa from 2005-2016 was estimated at 5.6% per year (BP statistical review, 2017). Africa's gas consumption is estimated at 138.2BCF in 2016 with Algeria, Egypt and South Africa leading consumption and accounting for more than 70%.

Gas consumption in Africa has been growing at a rate of about 4.9% per annum from 2005 to 2016. Even though Africa possesses huge gas resources, consumption is generally limited. North Africa has historically led Africa's gas sector production and consumption but recent growth from West African offshore oil boom comes with huge associated gas developments and huge recent discoveries offshore East Africa (Mozambique and Tanzania).

Ernest and Young (2013) stated that natural gas development in Africa present huge potentials and could be the game changer for broader economic and social development. However, these opportunities come with risk and challenges of which some are beyond the control of local/regional industries and governments. Ledesma (2013) noted that commercialisation of these resources comes with major challenges, among them are lack of infrastructure, environmental concerns, lack of finance for projects and high political risk.

Political stability is required to bring rapid gas development in Egypt and Libya. In West Africa, domestic consumption of gas is a major constraint and the underlying theme for future gas development is the monetisation of underutilised gas resource through reducing flaring and the capture of associated gas for export and more importantly for domestic use. The most important components for gas developments are downstream infrastructure development in power generation/industrial development and increasing local content focus (E &Y, 2013).

East African recent gas resources discovery in Mozambique and Tanzania presents a case of nascent gas industry development. Mozambique holds about 160TCF of recoverable gas reserves in the Rovuma Basin almost equal to Africa's largest gas reserves holder, Nigeria's 182TCF and same as Algeria's 160TCF. Tanzania, on the other hand, holds about 57TCF of recoverable gas reserves.

However, both countries have limited domestic consumption of gas, constituting 15% of energy utilisation in Mozambique and utilisation in Tanzania is only increasing marginally in electricity generation. Amanam (2017) noted that the gas resources discovered in Mozambique and Tanzania will contribute to the increasing global gas demand whilst serving the domestic demand in meeting energy needs. The development of these gas resources are challenged with: lack of adequate domestic markets and lack of infrastructure.

In an effort to utilise gas in Mozambique and Tanzania, strides are made to increase transparency and to develop proactive domestic gas utilisation programs and initiative, with an appropriate pricing structure. Both countries developed Natural Gas Master Plans. Mozambique, due to their vast gas reserves, aims to use LNG as their engine of development. Whilst Tanzania focuses on domestic utilisation in power generation as the most economically efficient option and later LNG (Deimierre et al., 2014).

Fruhauf (2014) and Ledesma (2013) identified political risk as a long-term headline risk to investors in these African countries. Institutional deficit poses the greatest challenge to near-term decision making due to acute skills shortage. Lack of specialist skills, transparency and corruption risk and overall infrastructure deficit poses a significant challenge to LNG export development and economic growth. Other challenges facing the domestic energy sector: social risk (unrest and social licence) from unfulfilled expectations and promises around the resource boom present major risk in the long-run. Demierre et al. (2014) recognised that a strong regulatory framework is required in infrastructure utilisation and key governance issues will have to be resolved in attempts to utilise gas resources for domestic purposes in Africa.

Mozambique's Gas Master Plan[17] recommended government support for infrastructure investment and the provision of a legal framework for governing gas development. A suitable gas pricing structure that will allow investors to secure an acceptable return on their investments and reward risk levels were recommended (ICF International, 2012).

[17] ICF International (2012) Natural Gas Master Plan for Mozambique Draft Report Executive Summary

Tanzania, on the other hand, has set out a gas policy[18], which set a framework for guiding the development of gas. Key challenges in developing Tanzania gas industry as summarised in the policy by Ledesma (2013) are:

- There is the need for an institutional and legal framework to administer effectively specific legislation to address governance issues with appointment of a regulatory authority.
- There is a shortage of skilled personnel to manage the gas industry.
- Gas infrastructure needs to be developed. The policy contemplates government ownership and non-discriminatory access of infrastructure.

Nigeria, on the hand, presents a mixed case study. Nigeria's natural gas reserves are estimated at about 182TCF with a projected 70% growth rate by 2025. Nigeria is among the top gas flaring nations accounting for 16% of global gas flares, which is estimated at about 1.3TCF annually (Odumugbo, 2010).

Nigeria has a suppressed power sector requiring investments in electricity generation with current available generation capacity, estimated at 2,500MW and installed capacity of 5,000MW. Nigerian current electricity demand is estimated at 10,000MW, far short of current available and installed capacity. To start with, Nigeria has a significant domestic market for gas in power generation. However, gas monetisation in Nigeria has always focused on improving LNG export at the expense of domestic consumption. LNG remains the largest utilisation strategy for Nigerian gas resources; however, recent focus

[18] Minister of Energy and Minerals (2013) The National Natural Gas Policy of Tanzania – 2013 – October, 2013.

is geared towards gas-to-power generation in several government initiatives in the National Integrated Power Projects (NIPP) and the Independent Power Plant Initiative. The Power Holding Company of Nigeria (PHCN) the incumbent and state monopoly was privatised and separated into six generation and eleven distribution companies (Nwaoha and Wood, 2014).

Odumugbo (2010) maintained that the Nigerians gas resources value is attained when it is used in country and plans are far advanced to boost power generation to 10,000MW by 2020 and this calls for additional infrastructure in 15,000km gas transmission pipeline, 16 new power plants and new gas distribution pipelines. Gas supply to power generation in Nigeria should be the priority of the government and all relevant laws to enhance this policy goal needs to be encouraged (Adekomaya et al., 2016).

Developing Nigeria's gas-to-power generation is faced with several challenges: lower upstream gas prices to power plants, which was intended to promote power generation but were not attractive to gas producers following the Domestic Gas Supply Obligation (DGSO) principle. Most importantly, delays in the passage of the Petroleum Industry Bill (PIB) as the bill promotes local content policies, which forces companies to invest in facilities for gas processing for further reuse, especially in power generation.

Nigeria has made frantic efforts to ensure the utilisation of their gas resources in developing a gas policy[19] with the vision of attaining a gas-based

[19] Nigeria Natural Gas Policy (2017)

industrial nation in meeting domestic requirements and international needs. The policy is set to establish an independent petroleum regulatory authority; legal separation of upstream from midstream: implement legal separation of gas infrastructure ownership from operation from gas trading and pursue a project based rather than a centrally planned domestic gas development approach.

In the area of industry structure, the Nigerian gas policy aims to move towards wholesale market-based competition, clear separation of roles between the private sector and government: restructuring the Nigerian Gas Company (NGC) into transportation and gas marketing and review the gas aggregation policy. In infrastructure, the policy intents to identify and proceed with key gas infrastructure and liberalised access to onshore and offshore gas transmission pipelines and gas processing.

The West African Gas Pipeline (WAGP) export natural gas from Nigeria to neighbouring countries (Benin, Togo and Ghana) operated by the West African Gas Pipeline Company (WAGPCo). The 678km pipeline has an initial capacity of 170MMscf/day and plans are far advanced to increase the capacity to 460MMscf/day and extending further west into Ivory Coast (Nwaoha and Wood, 2014). Eighty five percent (85%) of the gas WAGP transport is used for power generation and 15% for industrial purposes.

Nwaoha and Wood (2014) recognised that WAGP over the years failed to deliver the anticipated contracted volume of gas due to the plethora of reasons: policy, politics, infrastructure, funding, security and low prices offered producers. There are equally talks on a 4,500kms Trans-Saharan Gas Pipeline

(TSGP) between Nigeria and Algeria to transmit gas from Nigeria through Algeria into Europe. Nigerian gas resources have potential benefits in power generation and industrial development for the West African Sub-region.

Integrated studies of the industry structure, regulations and infrastructure investments decisions in these nascent gas industries will give a more appropriate perspective of their activities. However, the lessons learned from these studies as indicated on Table 19 include:

- There are common challenges in the development of the gas industries in Africa. For instance, Nigeria, Mozambique and Tanzania have similar challenges in institutional weakness; regulatory deficiencies; lack of infrastructure; high political risk; lack of appropriate gas pricing; weak and lack of appropriate regulatory frameworks and; high skills shortage and lack of expertise to manage the industry.
- These nascent gas industries in Africa (Mozambique, Tanzania, Ghana and others) can consider integrated studies of the structure, regulations and infrastructure investment decisions of their gas industries to provide an all-encompassing analysis.
- Stakeholder (investors, multinational organisations and national governments) engagements in these studies of the various gas industries are identified as important. These countries are attempting to develop gas master plans and policies to aid in the development of their gas industries.

Table 19: Gas Industry Development and Experiences from Africa

Reference	Sector	Definition of Sector Performance	Analytical Methods	Main findings & recommendation
Ledesma (2013)	Natural Gas	East Africa Natural Gas Potential for export.	Analytical framework and literature review.	*Main findings*: Mozambique has enough gas reserves for domestic consumption and exports. Tanzania has uncertainty on their exact gas reserves and consideration for domestic consumption or exports. Both countries face challenges such as financing, corruption and participation by undercapitalised and inefficient local partners in their nascent gas industries. *Recommendations*: finalisation of regulatory frameworks for both countries. Development of financial packages. Transparency with no perceived corruption, clear regulations and government decision-making process are vital for domestic and LNG export strategies for both countries.
Peng and Poundineh (2017)	Natural Gas and Electricity	Gas-to-power development in Nigeria and Bangladesh.	Analytical framework	*Main finding:* Regulation, Politics and International development partners plays major roles in gas-to-power development in Nigeria and Bangladesh. *Recommendation:* Privatisation is not the only path to improve operational efficiency and investments in gas and power infrastructure development but collaboration with multilateral development banks and other development partners is the most credible way.
Herath and Malhotra (1996)	Natural Gas	Development of an integrated cash flow framework for the analysis of natural gas value chain in Vietnam and Philippines.	An integrated framework and cash flow model	*Main Finding:* The model helped identify a set of negotiation for PSC terms, determine a suitable pipeline tariff for an independent pipeline company and gas price for the power plant. Sensitivity analyses are carried out, which help in negotiating production sharing contracts and determine pipeline, power tariffs and gas prices. *Recommendation:* A committed market and undisrupted pipeline are essential for the viability of the integrated gas project in the short and long run. The model can be used to negotiate IOCs and Government terms. Project development delays should be avoided.

Continuation

Fruhauf (2014)	Natural Gas	Mozambique LNG revolution political risk outlook.	Analytical framework and survey of literature	*Main findings*: Political risk can hinder the development of LNG in Mozambique. Including transparency and corruption risk, infrastructure deficits, challenges facing the domestic energy sector, labour challenges and social risk. Infrastructure bottlenecks pose the single greatest risk to LNG exports. *Recommendation*: Mozambique signed on Extractive Industry Transparency Initiative (EITI). Creation of sovereign funds and investments into infrastructure is advised. Local gas available support can be seen as a reason to invest in power plants. Strengthen existing education and labour training schools. The government needs to amend the legal regulatory framework to take into consideration LNG developments.
Odumugbo (2010)	Natural Gas	Natural gas utilisation in Nigeria: potentials and challenges.	Holistic framework	*Main Findings*: Nigeria gas reserves are estimated at 182TCF. Nigeria with its large natural gas resources still suffers from power crisis. It is imperative to exploit Nigeria's natural gas resources into improvement in the power sector. *Recommendations*: research should be encouraged in academia and government in finding out the utilisation options of Nigeria natural gas resources. There should be a regulatory framework to guide gas utilisation in Nigeria. There is a critical need to stop gas flaring, implement existing commitments in domestic gas markets, infrastructure for gas gathering and processing, and establish gas legislation. Develop local content in gas utilisation in industries such as methanol, ammonia; Gas-To-Liquids (GTL) and power are imperative.
Ernest and Yong (2013)	Natural Gas	Natural gas in Africa. The frontiers of the Golden Age.	Analytical review	*Main Findings*: Natural gas will be the "prime mover" for broader economic and social development in Africa. *Recommendation*: integrated gas development that could include power generation/industrial development are necessary.
Nwaoha and Wood (2014)	Natural Gas	A review of the utilisation and monetisation of Nigeria natural gas resources: current realities.	Analytical review	*Main Findings*: Nigeria has lost a major gas export market, USA. This requires the Nigeria government to encourage investments in the domestic utilisation of natural gas. Nigeria has resolved to a gas revolution program for economic development in gas-to-power, gas-to-liquid, gas-to-methanol, gas-to-fertilizer, and LNG projects. *Recommendation*: the development of conventional and unconventional gas resources has multiple benefits for Nigeria and this could be shared equitably for the benefits of all stakeholder (government, foreign investors and export customers).

3.2.3. Gas Industry Development from Ghana Perspective

The Ministry of Energy (2015) started the roadmap to developing a Gas Master Plan for Ghana. Ghana's gas volumes are not significant (6.4TCF) compared to other nascent gas countries such as Mozambique (160TCF) and Tanzania (57TCF) nor closer to Africa's largest reserves holder Nigeria (182TCF). LNG has been a major utilisation option for gas in developing countries because of the additional financial benefits to the governments.

Several empirical studies by international and consulting agencies, through series of methodologies such as Netback analysis[20] and strategic analysis[21] considered domestic gas utilisation for power generation as an economically superior strategy compared to LNG for export or for methanol production or for transportation fuel (CNG) in Ghana. The West African Gas Pipeline (WAGP) has been the first source of gas supplies into Ghana for power generation but offered unreliable and inadequate supply volumes.

Domestic infrastructure in support of gas-to-power sector development in Ghana has led to the construction of a 150,000MMBtu/d gas processing plant at Atuabo (Western region of Ghana) to receive associated gas from the Jubilee fields and subsequent production fields and a 114km gas transmission pipeline

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[20] Netback analysis involves taking the current market price of a product either domestic or global price for export and subtracting other capital and operational input costs to establish an estimated maximum willingness to pay for fuel supply. ECA and PDC netback analysis for Ghana's sector establish the transportation sector as the most viable sector for the use of natural gas, followed by the power sector.

[21] However strategic reasons (undertaken by the World Bank (2013&2015) emphasis on the use of Ghana's gas resources for power generation.

to connect to thermal power plants at Aboadzi (Western region of Ghana). However, there is a mirage of challenges, which constrain developing a domestic gas industry in Ghana.

Fritsch and Poundineh, (2016) identified lack of an effective regulatory framework for investments, skills shortages and an inefficient electricity pricing structure as constraining factors. The Ministry of Energy Gas Master Plan (2015) identified lack of clear policy framework; lack of stable regulatory and fiscal framework including fiscal conditions and gas pricing; and weak institutional and structural inadequacies in terms of the sectors design, competition and regulations posing a major risk to attract investments.

Furthermore, regulatory responsibilities are divided into upstream and downstream, and technical and economic regulations in Ghana, a mechanism that is unique to the gas industry, regulatory responsibilities and jurisdictions are not properly delineated. For instance, who regulates the role of the gas aggregator/supplier? Who regulates midstream infrastructure such as the FSRU and the gas processing plant? In addition, what are the regulatory jurisdictions of the numerous government regulatory agencies in the gas sector in Ghana? Gas price settings are not properly regulated considering the supply chain.

Developing a domestic gas industry in Ghana will require putting in place appropriate regulatory and structural arrangements that reduce risk and foster infrastructure investments. Previous empirical studies as indicated on Table 20 in the gas industry in Ghana emphasised on the utilisation options of gas resources. This thesis aims to tackle three major problems identified from previous empirical studies: in providing integrated analysis and appropriate industry structural arrangements; appropriate regulatory and governance arrangements; and considering business viability analysis in infrastructure investments decisions for the gas industry in Ghana.

Empirical studies from African gas countries (Nigeria, Mozambique and Tanzania) focused heavily on developing gas utilisation analytical frameworks of their gas industries. They, however, failed to provide integrated analysis. Integrated analysis of the gas industry provide a holistic framework for thorough identification and discussion of structural, regulatory and investment risk analysis. This study combines two study methods; developing an analytical framework based on SCP paradigm and TCE theory, stakeholder consultation through interviews to develop an integrated cash flow model of the supply chain components of the gas industry for Ghana. The lessons learned from previous empirical studies of the gas industry in Ghana are as follows:

- Domestic gas-to-power consumption is prioritised over an export strategy for Ghana's gas industry.
- Ghana will have to develop an integrated analysis of the structure, regulations and infrastructure investments decisions of the gas industry. In developing the integrated studies, emphasis should be placed on risk and business viability analysis of the various supply components of the gas value chain.

Table 20: Gas Industry Development and Experiences from Ghana

Reference	Sector	Definition of Sector Performance	Analytical Methods	Main findings & recommendation
Economic Consulting Associate and Petroleum Development Consultant (2014)	Natural Gas	Natural Gas Utilisation options in Ghana.	Netback analysis and a dispatch model	*Main findings*: The power sector is identified as the priority area for gas utilisation in Ghana. Appropriate regulatory framework and efficient institutions are required. The gas industry structure in Ghana is monopolistic in nature. *Recommendations*: develop a comprehensive gas sector act, provide a stable regulatory framework, ensure the financial viability of off-takers and associated creditworthiness of power and gas sector utilities. Additional supply capacity in the form of LNG is required for Ghana.
World Bank (2013)	Energy Sector	The role of the power and petroleum sectors in economic growth in Ghana.	Analytical framework	*Main findings*: natural gas will play a vital role in Ghana's energy future and ensuring adequate and reliable natural gas supply is fundamental to improving the cost of power. *Recommendations*: power generation is recommended as the priority for gas consumption in Ghana. The government must develop its credit approach to support gas development. Publication of the gas pricing policy in Ghana and perform commercial viability analysis for LNG and building of infrastructure to take care of future gas demand in Ghana.
Fritsch and Poundineh (2015)	Gas and Power Sectors	Gas-to-power market and investment incentives for enhancing generation capacity analysis for Ghana.	Analytical Framework	*Main findings*: lack of affordable and reliable fuel supply was a major problem in power generation in Ghana. Ineffective institutions and unfavourable investments climate resulted in poor electricity performance in Ghana. *Recommendations*: utilisation of gas reserves in Ghana's gas-to-power market is an economically superior strategy compared to export. Modification to electricity tariff to send a signal to investors without compromising on the affordability of power supply.

Continuation

World Bank (2015)	Energy and Infrastructure Sector	The World Bank Sankofa Gas Project to power Infrastructure Investments in Ghana.	Analytical framework and literature review	*Main Findings*: GNPC is responsible for the aggregation, transportation and commercialisation of gas. GNPC will be the off-takers of the Sankofa Gas Project. The power sector is a main gas consumer but financially constrained. The World Bank will guarantee $8billion of infrastructure investments into the gas sector in Ghana. Natural gas demand deficit is expected in the long-term that will necessitate the consideration of LNG. *Recommendation*: continuous risk Identification and mitigation should be taken seriously in the gas industry in Ghana.
Ministry of Energy-Ghana (2015)	Natural Gas	The Ghana Gas Master Plan.	Qualitative and Quantitative analysis	*Main Findings*: Gas demand will come from power generation, industrial use and transportation. LNG will play a key role in Ghana's gas supply. *Recommendations*: Develop a Gas Sector Policy Act. Provide a natural gas industry structure suitable to a nascent gas industry. Regulations should be unified to one institution. New gas pricing policy is required.
Ministry of Energy-Ghana (2012)	Natural Gas	Natural Gas Pricing Policy.	Stakeholder interviews and consultation	*Main Findings*: Power sector is the priority area for gas consumption; provide a framework for natural gas price negotiation. Natural Gas Reserves in Ghana are estimated at 6TCF. Energy Commission Act 1997, 541 calls for unbundled transmission pipelines. BOST was awarded the NGTU. *Recommendation*: Monopolistic industry structure. Providing data set for the natural gas/energy sector to enable continues monitoring and accessing the effectiveness of policies. Provide a clear framework for the introduction of LNG. Gas must be economically priced to ensure full cost recovery of all investments. Unbundling of the Gas Industry shall occur only after 10years.
Nexant (2010)	Natural Gas	Gas sector master plan – advisory paper.	Stakeholder interviews and consultation	*Main findings*: Power and industrial demand should be the main areas of focus for Ghana's gas resources. *Recommendation*: Improve the quality of energy data in Ghana. A thorough analysis of projected electricity demand in Ghana. There is the need for a detailed regulatory policy document, which will outline natural gas industry regulatory structure in Ghana. The regulatory structure should clearly set the roles and responsibilities of each player, how infrastructure will be regulated and competition is to be encouraged.

3.3.0. Strands of the study

The section focuses on the three objectives of the study. These are classified into three strands: strand 1: structuring the gas industry; Strand 2: Business Viability of the supply chain components of the Gas Industry and strand 3: Regulation and governance arrangements in the Gas Industry in Ghana (as discussed in Chapter 2 section 2.5.3: Natural Gas Industry Institutional Arrangements in Ghana).

3.3.1. Strand 1: Structuring the Gas Industry in Ghana

What is the current structure of the gas industry in Ghana? It is hard to find empirical evidence supporting the theory of market structure in the gas industry (Joskow, 2002; Arora, 2012). Much of the available literature is borrowed from other networked industries such as the electricity sector. Bhattacharyya (2011) identified six industry structures for the power sector[22]. Juris (1998) however, focused on gas industry structural models: Vertical integration; Competition in natural gas production; Open access and wholesale competition; and Unbundling and retail competition.

The discussion focuses on the nascent gas industry in Ghana. The structural models considered includes the combination of Bhattacharyya (2011) power sector models and Juris (1998) gas industry structural models: Vertical Integration Model (VIM) or the Single Buyer Model (SBM), Multiple Buyer

[22] Bhattacharyya (2011): Vertically integrated monopoly; Monopsony (single buyer) model; Transitional models; Price-based pool and wholesale competition; Cost-based pool and wholesale competition; Open access and wholesale competition; and Full customer choice.

Model (MBM), Competition in natural gas production, Open Access and Wholesale competition, and unbundling and retail competition.

3.3.2. Model 1: Vertically Integrated Model (VIM)

Vertical integration is the traditional structure of the gas industry. Production, pipeline transportation, and distribution are performed by one utility to benefit from economies of scale (Bhattacharyya, 2011). Such a company has an exclusive position in gas supply to end users (Juris, 1998). Integration is seen as a way to prevent opportunistic behaviour and hold-up problems from other companies and concentrates assets ownership and operations to a single entity (Oliver and Moore, 1990).

When is it appropriate to operate VIM and to what extent? This fits well with the early development stages of the gas industry due to the site-specific and dedicated nature of infrastructure requiring long-term contracts to provide security to investors and guaranteed returns on investments (Glachant et al., 2014). What are the benefits of VIM? VIM offers firms incentives to maximise the aggregate gains from trade associated with transactions without any offsetting costs of the internal organisation. VIM has superior efficiency properties to decentralise trade between independent buyers and sellers in a market (Joskow, 2002). In essence, VIM seeks to maximise the joint profits of its upstream and downstream operations because pricing decisions are coordinated in a way that leads to profit maximisation (Bresnahan and Levin, 2012) and eliminates information asymmetry between upstream and downstream divisions, thus enabling better coordination (Riordan, 2008).

VIM coupled with regulations ensure that consumers receive reasonable prices and through government initiatives, gas can be delivered to longer distances and to rural areas. VIM can be the most efficient response to uncertainty and contractual incompleteness (Bresnahan and Levin, 2012; Williamson, 2010). VIM can lead to the easy settlement of minor conflicts than haggling and litigation (Williamson, 1971).

VIM could provide technological and economic advantages to the industry in that having a single firm means that the firm can easily take up technological innovations to improve on its operations at a much lower cost possible (Barrera-Ray, 1995). However, in VIM, the single firm will usually require heavy regulation because of its monopoly position since such industries lack the flexibility required in a dynamic market environment and even regulation is often insufficient to induce it to operate efficiently (Juris, 1998).

VIM alters the bargaining power of producers, reduces innovation from others and protect returns from its own innovation (Riordan, 2008). This may, in the long run, result in higher prices. VIM can be used to strategically lessen competition in the short-run by raising rivals' costs or in the long run by increasing rivals' cost of market entry (Joskow, 2010). Whenever a firm operates in VIM and self-supplies itself with some inputs, other potential suppliers are in some sense "foreclosed" from providing those inputs and therefore "forecloses competition" (Joskow, 2010). In effect, if not checked VIM prevents future introduction of competition into the industry.

A key concern to a nascent gas industry such as Ghana is how VIM will keep the industry viable and attract infrastructure investments. VIM is obviously favoured when there is an urgent need to monetise flared gas with imperfect and uncertain downstream markets. In this instance, Joskow (2010) postulated that the benefits of mitigating opportunism problems that may arise because of specific investments under VIM are greater than the cost of other sources of static and dynamic inefficiencies that may be associated with allocations within bureaucratic organisations, so it is preferable to opt for VIM.

Uncertainty mitigation in the early commercialisation of the gas value chain is considered as one of the main drivers for VIM (Claussen, 2011). Uncertainties are reasons to follow VIM especially when the uncertainties affect multiple stages of the value chain. VIM is attractive but if the uncertainties affect only one stage, contractual relationship is appropriate (Claussen, 2011; Barrera-Ray, 1995). The implementation of VIM requires a balancing act: to prevent the misuse of monopoly power while ensuring adequate revenue to firms (Bhattacharyya, 2011).

Regulations in VIM is not usually an easy task due to the conflicting nature of the role of the state and in many instances, the tariff structure is always divorced from cost structure. Subsidies and cross-subsidies are used to manipulate tariffs for specific advantage, and the utilities do not have incentives to improve performances, which leads to inefficiencies (Bhattacharya, 2011). As a result, alternative models are considered.

3.3.3. Model 2: Single Buyer Model (SBM)

A modified version of VIM is SBM. The SBM introduces a single purchasing agency at the wholesale level. This single entity is often state-owned, performs transmission and wholesale supply functions (Bhattacharyya, 2011). This centralised agency has some role in coordinating supply and demand (Castalia, 2013). Gas producers/suppliers enter into gas purchase contracts with the single buyer who in turn performs the trading function (selling) gas to consumers. For the effectiveness of SBM, gas producers/suppliers, transmitting companies and consumers must work independently and tariffs set by an independent regulator (Celik, 2003).

How does the SBM work? Production and supply of gas is undertaken by multiple entities such as several IOCs and gas traders supplying gas (Kasim, 2014) different from VIM. In the production segment, the single buyer through long-term purchase contracts procures the required capacity volumes of gas. The single buyer pays the producers under long-term contracts and the contracts are for the economic life of the oil and gas wells (Castalia, 2013). The single buyer then delivers the gas to consumers through a regulated pipeline, under the ownership of the single buyer or a different owner.

Lovei (2000) stated the advantages of the SBM as; SBM allows easy management of the sector in decision-making processes and investment in additional supply capacity. SBM turns to maintain a unified wholesale price and simplifies tariff regulations. The SBM makes it possible to shield financiers of major gas supply projects from market risk and retail-level regulatory risk, reducing financial costs and making the investment commercially bankable.

SBM can be seen as a transitional structure before introducing wholesale competitive markets. In general, SBM is seen as providing a relatively simple and quick first step towards competition and a mechanism for handling stranded costs (Lovei, 2000; Celik, 2003). SBM allows multiple gas producers participation and thus opens the production segment to participation and facilitates the vertical separation of activities, which provides better cost information and scope for improvement (Bhattacharyya, 2011). The single buyer in Gas Sale Contract provides a guaranteed purchaser of gas at a certain price. SBM is able to make social benefits considerations; maintains uniform retail tariffs and can even facilitate tariff discrimination.

However, SBM is seen to provide no clear signal for improving the transmission network and has a very complicated regulatory structure and not setting up the independence of the institutions that eventual competitive market will require (Lovei, 2000). SBM assume full responsibilities in the entire gas sector but does not take responsibility for final consumption and sales, which the entire gas industry is dependent. As the revenues flow backward, from the consumers to the single buyer any default from the consumers due to either poor tariff rates or inefficiency or a combination of different factors, can lead to default of the entire value chain (Bhattacharyya, 2011).

SBM is likely to be influenced by politics or government control and considered as a dangerous option (Lovei, 2000; Bhattacharyya, 2011).

Moreover, once the single buyer enters into a long-term contract with the suppliers or producers it becomes difficult to undertake further reforms (Bhattacharyya, 2011).

3.3.4. Model 3: Multiple Buyer Model (MBM)

The MBM is considered a transitional model from VIM or SBM to competition. This model has been advocated for small systems because the risk of directly moving to spot markets may outweigh the benefits. The idea behind MBM is to adopt an intermediate structure for a transition period at the end of which the industry moves to final competitive structure (Bhattarcharyya, 2011).

The intermediate model should be appropriate, compatible and not create hindrance to reach the final structure. This transitional model can take up one or two features of VIM or SBM or the final wholesale competition model (Bhattacharyya, 2011). Two of such models are identified as multiple-buyer multiple-seller model without retail competition (MBM: A) and multiple-buyer multiple-seller model with limited retail competition (MBM: B).

In both models, gas production and supply, transactions are unbundled from transmission services and a number of producing and supply companies would operate in the system. Similarly, there would be a number of distributing companies, which may be regulated monopolies (Bhattacharyya, 2011).

Multiple-buyer multiple seller model without retail competition (MBM: A): The supply market would have two components: a competitive segment and a non-competitive segment. The non-competitive segment acts as the single buyer model where the producing/supply companies would sell gas through a gas purchase agreement to the balancing buyer/seller. Nevertheless, some gas would be available for trading competitively. This can be achieved by defining the proportion of gas supply capacity to be released from producers/suppliers Gas Sales Agreements to the balancing buyer-seller.

Initially, the proportion of available competitive gas would be relatively small but this could be increased over time. Producers/suppliers would compete with each other for selling their competitive portion of gas to consumers using bilateral contracts with physical delivery. The balancing buyer-seller would sell gas to consumers under a regulated bulk supply tariff. The balancing buyer-seller could be the transmission company, which is often a state-owned company (Bhattacharyya, 2011).

Multiple-seller multiple buyer model with retail competition (MBM: B): introduces a limited amount of retail competition by allowing larger consumers to purchase gas directly from producers/suppliers through bilateral contracts. Competition arises from the retail level, as eligible customers would have the choice of taking gas from the producers/suppliers directly (Bhattacharyya, 2011). Large customers are selected on some criteria such as consumption volumes or size of companies.

The model allows for some wholesale competition and provides incentives on producers/suppliers to improve efficiency. Frequent price determination will allow the reflection of production and supply cost more accurately determined and shorter trading periods would encourage the development of short-term bilateral contracts to manage the risk faced by market participants (Bhattacharyya, 2011).

Initially, the markets are regulated to provide the needed level of certainty to potential investors and at the same time, it avoids a major problem of SBM by allowing risk to be shared by all market participants. It provides a foundation for introducing competition and an opportunity to simulate spot market operations (Bhattacharyya, 2011). However, the model implementation is complex than VIM or SBM. Both producers/suppliers and consumers will be exposed to risk, as the financial viability of both would be interdependent and this limits the possibilities of cross-subsidisation (Bhattacharyya, 2011).

3.3.5. Model 4: Competition in Natural Gas Production

The gas industry in recent times is experiencing new trends in reforms in unbundling VIM, and opening wholesale gas markets to new entrants and stimulating competition in gas production/supply. The liberalisation policies aimed at breaking traditional state monopolies led to the new entrance and market segmentation, which allows entries on the production/supply side and enable consumer switching on the demand side (Cavaliare, 2007). Recent examples of such liberalisation processes include the European gas industry, which has three features: unbundle potentially competitive segments of the industry: Third Party Access to essential facilities and competition in the demand side, thus allowing consumers to switch suppliers.

What are the benefits of competition in the gas industry? In seeking to reduce uncertainty, improve efficiency, reduce or eliminate the hold-up threat and over-dependence on single/few purchasers, competition introduces flexibility and economic rationality (OECD, 2000). De Mello Sant Ana et al. (2009) stated that, if competitive markets are well conducted, dependenting on access to gas supplies they tend to reduce prices to downstream consumers and propitiate improvement in the security of supply by creating new flexibility mechanisms capable of balancing supply and demand. If gas supply is limited and there are constraints to adequate supply, prices will not reduce and security of supply will not increase.

Competition in the gas industry is expected to promote additional sources of supplies (Robert and Harman, 2002). Competition ensures energy security and supply diversity, improved accessibility, operational optimisation allowing market liquidity and flexibility in the local gas market. For the private sector promoting competition is a signal for market certainty in regulations, transparency and long-term structures (International Gas Union, 2004).

Why should the introduction of competition into a nascent gas industry be a structural alternative? The logic of competition, as posited by Economides (2003) is to guard against restrictions, impediments, and maximisation of efficiency. Competition seeks to stimulate non-discriminatory open access through regulation focused on information transparency and tariff regulation (Ana et al., 2008). Lack of competition in one segment of the gas sector can affect the competitiveness of the other sectors and introducing competition in one segment; stimulate competition in others (Robert and Harman, 2002).

How can competitive structures in a nascent gas industry attract infrastructure investments? Different from VIM, competition will require the consideration of keeping gas production as part of oil and gas activities. Ernest and Young (2014) recognised that uncertainty and risk in weak legal institutions and inefficient and ineffective institutions are among several other factors affecting investments into the development of oil and gas resources in Africa and the introduction of competition is hoped to strengthen existing institutions.

Will competitive structures reduce investors' risk for nascent gas industries? There are three risks factors to investors in these nascent gas industries. Lack of safeguards to ensure gas is delivered to end-users. Lack of regulation in transportation activities. Weak institutional and regulatory arrangements to ensure that investor's remunerations and incentives are enough to promote further investments in providing adequate gas pricing and appropriate economic tariffs (Ana et al., 2008).

Competition introduces choice to retailers and eligible customers at the wholesale level and avoids some of the pitfalls of SBM and MBM. The model provides efficient economic signals to generators and retailers. All market participants and not only the single buyer take up credit risk (Bhattacharyya, 2011). Investment decision-making is decentralised to market participants, liquidity in the market is increased to encourage new market entrants. With an effective open access regime, competition in upstream gas production offers easy transition to full customer choice models (Norwak, 2010; Bhattacharyya, 2011). However, the asset specificity nature of gas investments does not make competitive structures in the nascent gas industry an option at the developmental stages, unless there is certainty of cost recovery for potential investors in guaranteed buyers of gas at economic tariffs investors will be deterred. Competition does not give a guarantee of cost recovery and is not an initial industrial structural option especially for nascent gas industries.

3.3.6. Model 5: Open Access and Wholesale Competition

Open Access (OA) is the mandatory wholesale access where legitimate users are offered effective, transparent, fair and non-discriminatory access to the pipeline network and paying regulated tariffs (Kramer and Schnurr, 2014; Hallack and Vazquez, 2014). This includes the ex-ante set of rules for infrastructure usage (Hallack and Vazquez, 2014). Open access implies allowing entry to the market through access to essential facilities such as transmission and distribution network (Bhattacharyya, 2011).

The essential infrastructure owners under the VIM tend to express opportunism (Williamson, 2010) i.e. to favour their own subsidiaries and block new entrants (Nowak, 2010). To solve this problem, non-discriminatory access to essential infrastructure is required (Nowak, 2010). These essential facilities are considered natural monopolies which cannot be economically duplicated and occupy a strategic position in the industry (Austrian Competition and Consumer Commission and Public Utility Research Centre, 1997).

Von Hirschausen (2008) and Willaimson, (2010) argued that vertically bundled companies that own the infrastructure and participating in the trading segment of the industry, are irrationally bounded and have fewer incentives to invest in infrastructure expansion as compared to an unbundled infrastructure network where profitability drives infrastructure investments. The reason being that, the integrated company have access to the infrastructure and letting-out a third party would defect the opportunism of the integrated company.

There are two forms of Open access: regulated and negotiated open access. Under the regulated Third Party Access (TPA), the regulatory authorities set the tariffs and other terms and conditions of use of the pipelines, which are applicable to all users alike. Negotiated TPA, on the other hand, allows eligible users of the pipelines to negotiate voluntary commercial agreements with the infrastructure owner (Bhattacharyya, 2011).

In an open access regime, the infrastructure owner has no right to discriminate among legitimate users and impede the network from colluding with certain players while excluding other players from accessing the transmission grid (Glachant et al., 2014). Ghana has existing open access policies on gas transmission pipelines as indicated in Box 3.

How effective is the open access regulatory policy in Ghana? One way to determine if an open access regime is operational is to ask if a company/customer can switch its supplier. Which implies that, suppliers/traders have easy access to the networks and that this access is equal, transparent and based on well-defined tariffs (Nowak, 2014). On the other hand, whether the percentage of customer switching suppliers is high or low and whether customers are not locked into specific long-term contracts (Nowak, 2014).

Box 3: Open Access Regulations in Ghana

Energy Commission, Natural Gas Transmission Access Code: Gas Transmission Services are to be provided on a non-discriminatory basis. This Code is to promote the development of a competitive gas market by instituting uniform principles for owners and users of gas pipelines and allow transparent and non-discriminatory access to the transmission systems. Prevent abuse of power by the Natural Gas Transmission Utility (NGTU); provide rights of access to the transmission systems on conditions that are fair and reasonable for both service providers and users. **West African Gas Pipeline Access Code Part A and B:** The Code is published pursuant to clause 26 of the International Project Agreement (IPA), which allows WAGP to operate under an Open Access system: transportation services are to be provided based on non-discrimination. The WAGP Authority is the enforcement authority of the access code.

Source: Energy Commission (2014); WAGPCo (2004).

Open access alone is not a sufficient condition to ensure the objective of any reform process. Third Party Access (TPA) implementation may lead to intrusive and burdensome regulatory oversight, which may not lead to the full benefits of reform as the structure of the industry undergo little changes (Bhattacharyya, 2011). To deepen competition is to unbundle VIM completely.

3.3.7. Model 6: Unbundling and Retail Competition

There are concerns on whether open access under VIM, SBM or MBM will deliver the non-discriminatory access to essential facilities and whether these alternative structures will indeed deliver efficient and timely infrastructure investments (Pollitt, 2007). Unbundling and retail competition provides the solution and this is the ultimate structure in the gas restructuring process where all customers have equal access to competing producers/suppliers, access to infrastructure and option for supplier switching (Bhattacharyya, 2011). Retail competition is the complete separation of gas production/supply and retailing from the transmission network business to allow all customers to choose their suppliers (Bhattacharyya, 2011). The model allows competition in production, wholesale, retail and open access to gas transmission and distribution networks.

Effective implementation of unbundling will result in lower prices, better quality, and innovation than expected under-regulated regimes, if there are excess capacity and adequate gas supply to meet demand and would result in efficient production, investments and consumption and improve allocative and productive efficiency. The emergence of the spot market would provide an investment indicator for investors in gas production/supplies and improve investments (Bhattacharyya, 2011).

However, unbundling is weak in the gas industry as compared to the electricity industry and this is mainly because gas can easily be substituted for other fuels as compared to electricity (Haucap, 2007). Unbundling as an industry structural alternative has not been used extensively for the gas industry as compared to the electricity industry and much of the studies on the cost and benefits of unbundling are related to electricity generation, transmission and distribution segments. This study will attempt to explore the benefits of unbundling to the nascent gas industry in Ghana. The consideration of unbundling as a structural alternative will require effective regulatory oversight, which may not have previously existed (Pollitt, 2007). The implementation of the model will require technical managerial skills and therefore difficult to implement (Bhattacharyya, 2011) in a nascent industry.

3.3.8. Evaluating Criteria for the Structural Models

Which of these models will be a best-fit structural model for the nascent gas industry in Ghana? These models will need to be evaluated against selection criteria to identify the most suitable model. The evaluation criteria are adapted from the World Bank (2018) RISE project (Regulatory Indicators for Sustainable Energy). RISE is the first global policy scorecard of its kind grading 111 countries in three areas on energy access, efficiency and renewable energy.

The RISE project is aimed at helping government assess if there is a policy and a regulatory framework in place to drive progress on sustainable energy and pinpoints more on what can be done to attract investments. RISE classifies countries into a green zone of strong performers in the top third, a yellow zone of middle performers and a red zone of weak performers in the bottom third. The RISE project is adapted and modified for evaluating the gas industry structural models: on reaching to gas consumers; making gas affordable to consumers; reliable supply of gas; viable supply chain; attracting investments; reducing risks; ease of implementation and regulation.

Additionally, Eberhard (2007) and Mckinsey (1993) provided structural model evaluation criteria where the various models are measured against a series of variables such as number of buyers and sellers, asset specificity, transaction frequency and uncertainty as indicated on Table 21.

The balance of power between buyers and sellers determine the terms of transactions in an industry (Mckinsey, 1993) and the type of model required. Where there are only one buyer and one seller, especially in a long-term relationship that involves frequent transactions, VIM is considered appropriate and as the features reduce the model evolves (Mckinsey, 1993).

Table 21: Evaluation of the Structural Models

Structural Elements	**Evaluation Questions**
Number of Sellers	One seller, Few sellers or many sellers, no one dominant seller
Number of Buyers	One buyer, few buyers or many buyers, no one dominant buyer
Asset Characteristics	
Specificity	Site specificity, technical specificity and human specificity.
Intensity	Asset Intensity
Durability	Durability: long term or short term contracts.
Transaction Frequency	Haggling, negotiations and renegotiations.
Uncertainty	Bounded rationality and opportunism.

Source: Adapted from Mckinsey (1993).

There are three factors in asset characteristics that affect the organisation of industry structures: specificity, intensity and durability, which raise switching cost and compartmentalises industries into VIM, SBM, MBM or Unbundling (Mckinsey, 1993).The degree of asset specificity determines the types of transactions and frames a signal for the type of industry structure model to adopt. A higher degree of asset specificity in long-term contracts will require VIM but as assets become re-deployable, the degree of VIM reduces and as more players are introduced, this will require open access to infrastructure.

High capital intensity and high fixed costs increase the cost of any production disruption because of the magnitude of both cash and opportunity cost incurred during the interruption. In addition, asset durability increases the time horizon over which the risk and costs are relevant (Mckinsey, 1993). Put together, higher asset specificity, intensity and durability often course high switching cost for both buyers and sellers and asset specificity has the highest degree in determining industrial structural organisation.

High transaction frequencies raise cost since haggling and negotiation occur more often and allow for frequent exploitation, which is present in a typical VIM: in such instances, alternative structural models are considered. Uncertainty makes it difficult for companies to draw up contracts that will guide them as circumstances change and VIM locks companies to a single buyer even under uncertain conditions. Higher uncertainty exposure to a single firm under the VIM means that alternative models should be considered.

In essence, the nascent gas industry structural models evaluation criteria in Ghana are measured on the basis of the objective of the industry in reaching to more gas consumers; making gas affordable to consumers; reliable supply of gas; viable supply chain; attracting investments and investors; ease of implementation; ease of regulation; reducing asset specificity; transaction frequencies and reducing risk/uncertainties.

3.4.0. Strand 2: Business Viability of the Gas Industry in Ghana

This section reviews literature on risk/uncertain investment conditions in the nascent gas industry in Ghana. Unfavourable investment climate was identified as a major challenge to business viability in the gas industry in Ghana (Fritsch and Poundineh, 2016). What are these unfavourable (risk and uncertainties) investments conditions and how can they be mitigated? How viable are supply components of the gas industry chain and what are the uncertainties affecting the viability of the gas industry in Ghana?

3.4.1. Risk Factor Identification in the Gas Industry in Ghana

Conditions with unknown negative outcomes are termed risk or uncertainties (ADB, 2002). Whilst risk is the quantity subject to empirical measurement, uncertainties are non-quantifiable (ADB, 2002). Investing in natural gas projects has similarities to investing in oil and power projects. Upstream gas projects are modelled like oil projects, mostly left to private companies and joint venture entities (Razavi, 2007).

Financing projects in the gas industry in a developing country are considered riskier than financing similar projects in the developed world. Investors want higher returns to compensate for higher risk and would want to diversify their risk and take mitigation measures (Razavi, 2007). Developing countries present to international investors unfavourable business environments, in institutional and organisational deficiencies in structural rigidities or vague divisions of responsibilities in weak regulatory systems.

Bhattacharyya (2011) noted that energy investments are exposed to several risk factors at different levels, which are categorised into four levels: external, macro, meso and micro. At the external level, changes in global market conditions, financial markets, international trade, and environmental laws can affect investment decisions.

At the country-specific level, political and regulatory influences can affect investments. At the macro level, risk arises from possible changes in the political condition, regulatory environment or economic/financial conditions of the country. The economic viability of projects are affected by changes in currency valuation and the possibility of labour unrest.

At the meso and micro levels, government-related issues could have major concerns. Three factors can be highlighted: law and order situation may not be conducive for undertaking investment projects. Terrorist and militant activities, kidnapping and other anti-social activities may prevent or delay the implementation of projects; high levels of corruption could adversely influence investment decisions, and politicisation of projects could lead to delays of projects (Bhattacharyya, 2011; Pend and Poundineh, 2017).

At the micro-level, economic risk, volumetric risk, market risk and consumer risk, commercial risk as well as project implementation risk can influence investment decisions (Bhattacharyya, 2011). Schindlmayr et al. (2007) identified credit risk as one of the important micro-level risk factors where a party to a contract is unable to fulfil his contractual obligations of payments of agreed physical deliveries or acceptance to counterparties.

These micro-level uncertainties (risk) according to Yescombe (2002) are generally classified into three: commercial, political and financial risk as indicated on Table 22. Commercial risk or project risks are those inherent in the project itself or the market in which it operates; financial risk or macroeconomic risk relates to external economic factors not directly related to the project and political risk or country risk relates to government action or political force majeure. Political and economic risk are also common in developing countries' business environments. Economic risk affects the ability of consumers to pay for project output. Political risk can raise costs, reduce revenues and in certain cases result in total loss of investments or returns on investments (Razavi, 2007). Leppard (2005) considered market risks to encompass commodity, foreign exchange and interest rate risks and exposure to uncertainties in these traded markets and physical risk such as force majeure and volumetric risk.

James (2008), related operational risk as the loss caused by failure in operational processes or the Information Technology (IT) systems that affect the whole system including those adversely affecting reputation, legal enforcement and contractual claims. Leppard (2005) grouped all these risks into a risk galaxy, which describes the full range of risks that a transaction may expose an energy company to as captured on Table 22.

Table 22: Risk factors common to the natural gas industry

Risk	**Examples**
Commercial Risk: The influence of internal factors on gas projects.	Project viability risk, completion risk, environmental risk, operational risk, revenue risk, raw materials and energy supply risk, contract mismatch risk, position concentration risk, operational risk, reputational risk, force majeure, volumetric risk, systems/procedural risk, tax risk, compliance risk, counterparty concentration risk, credit risk, price risk, and basis risk.
Financial Risk: effects of different economic factors, which influences the realisation of projects in the gas industry. Their influence is indirect since they affect the economic environment of the project.	Inflation risk, interest rate risk, exchange rate risk, modelling risk, proxy risk, raw data risk, accounting risk, currency risk, funding liquidity risk, liquidity risk, and cash-flow risk.
Political Risk: refers to the possibility that the government or political authorities in the country can influence development in the gas industry	Political risk, investment risk, regulatory change or legal system change risk and quasi-political risk. Eg. War, civil unrest, expropriation, breach of undertakings by the host government, expatriation of profits, inconvertibility of a developing countries currency, litigation risk, sovereign risk, and country default risk.

Source: Poznanic et al. (2011).

Traditionally, the uncertainties that the nascent gas industry in Ghana is exposed are not different from those identified above. Other possible risk factors include the risk of upstream investment viability, which requires a reasonable gas price and downstream consumer's ability to pay, as they require low prices to stay viable, and the risk of arriving at an adequate gas price that will meet the expectation of all stakeholders.

There are other possible risk factors such as foreign exchange, delays in project development, lack of supporting infrastructure, lack of credible off-takers at the downstream, competition from other fuels such as LCO and competition from renewable energy, risk of appropriation and many more.

3.4.2. Risk Evaluation in the Nascent Gas Industry in Ghana

To evaluate the risk factors and their impact on the viability of the supply chain components of the gas industry in Ghana, several risk valuation models are considered: such as Life Cycle Assessment (LCA) model and input-output models. LCA is the compilation and evaluation of inputs, outputs and the potential environmental impact of a product system throughout its lifecycle. LCA is used to provide a better understanding of the environmental impact of the product and its effects on each step of the chain and to show the competitive advantage of a product by showing its impact on the environment (International Gas Union, 2015). LCA has been used to access environmental impacts in LNG import projects and receiving terminals to identify synergies that reduce all environmental impact by sharing infrastructure asset (IGU, 2015).

The input-output model has been used for economic analysis in the energy sector, it provides a consistent framework of analysis, and can capture the contribution of related activities through inter-industry linkages (Bhattacharyya, 2011). The scenario approach has been widely used in climate change and energy efficiency analysis, which narrates a set of illustrative pathways of possible future events and how they unfold.

Bhattacharyya, (2011) posited that scenario analysis evidently does not capture all possible eventualities but tries to indicate how things could evolve, as the approach tries to use an analytical structure to examine future uncertainties and identify future pathways and estimate uncertainties. The main advantage of scenario approach is its ability to capture structural changes explicitly by considering sudden changes in the development paths.

The theory of investment under uncertainty (Dixit and Pindyck, 1994) applies the Net Present Value (NPV) principle in project decision making to determine the economic viability of projects (ADB, 2002). NPV converts all benefits, cost of projects occurring at different points into their present value equivalent, and aggregate them into the overall cost and benefits of the project (Bhattacharyya, 2011). NPV's are usually considered the preferred methods in project evaluation and selection compared to Internal Rate of Return especially when both results are contradictory (Bhattacharyya, 2011).

This study considers the evaluation of the supply components of the gas industry using NPVs to determine the viability of upstream production, processing, transmission and consumption of gas to power generation in Ghana. The leading question is why should an IOC or a potential investor expose to risk invest in the integrated gas value chain in Ghana? A basic method to determine this is to calculate the NPV of the project supply components.

Sensitivity analysis measures the sensitivity of decisions to changes in the values of one or more parameters. Sensitivity analyses are performed when the conditions of uncertainty exist for one or more parameters (ADB, 2002). The objectives for undertaking sensitivity analysis is to help identify key variables affecting the viability of the project; investigate the consequences of likely changes in those factors; access reversal potentials and alternative investments and mitigation measures (Bhattacharyya, 2011; ADB, 2002).

Sensitivity analysis fails to capture correlation and probabilities in changing events, (Bhattacharyya, 2011) as a result this is complemented with simulation analysis. Jehl et al. (1999) identified three simulation methods for oil and gas projects: option pricing, decision trees and Monte Carlo simulation. Option pricing uses Black and Scholes models for spot prices and expresses the value of the project as a stochastic differential equation. Decision trees neglect the time variation in prices but concentrate on estimating the probabilities of possible values of the project using Bayes theorem, prior and post probabilities.

Monte Carlo Simulation (MCS) captures probabilities and correlations in future events and require the user to specify the marginal distribution of all the parameters appearing in the equation of the NPV of the project. The simulation analysis fills the gap in sensitivity analysis by providing correlation and probability analysis (Jehl et al., 1999). MCS, however, assumes a fixed project life and does not allow for management flexibility (Jehl et al., 1999).

Risk evaluation using MCS is carried out using specially designed software such as RiskMasters, @RISK and Crystal Ball, which are adds-on to Microsoft Excel spreadsheet programs. Comparatively, the @RISK software package is identified as highly suitable for undertaking Monte Carlo based simulations to drive probability distribution outcomes, fitting distributions to dataset outcomes and viewing graphically the distribution of variables and outcomes (ADB, 2002). Simulation and Sensitivity analysis are performed on the project NPVs, with outputs showing the impact of varying the key risk factors on the viability of the projects to identify which risk factors are financially sensitive to decreasing NPV and mitigation measured identified (Kasriel and Wood, 2014).

This study develops an integrated cash flow model involving the gas value chain in Microsoft Excel spreadsheet to determine the business viability of the supply chain components, perform simulation analysis using @RISK software, and perform sensitivity/correlation analysis to identify uncertainties and areas of enhanced competitiveness in the nascent gas industry in Ghana.

3.5.0. Strand 3: Regulation and Governance Arrangements

It is important to note that, the regulatory framework, governance arrangements in the gas industry will depend on the industry structural model adopted. This has to evolve as the industry develops with decreasing. An effective regulatory framework will need to take retrospective and futuristic perspectives and adopt to the structural changes and risk/uncertainties as the industry evolves. Regulatory and institutional arrangements in the gas industry in Ghana are presented in Chapter 2 (section 2.5.3.).

Under VIM/SBM, effective regulations are required to prevent abuse of monopoly power, setting prices and ensure effectiveness. As the structural model evolves from SBM to MBM, the regulatory requirements are minimised until full competition is achieved where regulation is minimal.

The regulatory regime under a vertically integrated structure is an administrative supervisory relationship between the government entity responsible for utility regulations and the state-owned companies. The regulatory entity responsibility, in this case, is to approve the overall tariff, design the structures that allocate the cost of energy provision among different sectors of the society and to set objectives for the industry (Peng and Poundineh, 2016). Regulations in VIM are relatively simple because government regulation on industry behaviour is compared to competitive industries where self-regulation is required. (Peng and Poundineh, 2016).

In the competitive industry structure, ownership is dispersed among many different agents; both public and private participants operate in economic and market conditions. The government, via the activities of the regulatory authorities, interact with many companies along the gas value chain. Typical institutions include the ministry concerned, the regulatory authority more or less independent of the ministry.

Regulations in competitive markets are those that promote effective competition by addressing market failures such as imperfect competition, imperfect information and externalities. In the gas industry, this means:

unbundling and regulating the network: liquidity and competitiveness check for the other segments: correction of information asymmetry between suppliers and consumers and control of external factors. Infrastructure investment regulation is directly linked to economic regulation[23].

Economic regulations address a major problem in infrastructure investment: how will cost be recovered? (Phillips et al., 2016). An effective Regulatory framework must examine two basic dimensions of the regulatory system: regulatory governance[24] and regulatory substance[25] (Gencer et al., 2006). Jamison et al. (2014) noted that economic regulations deal with regulatory independence and investors value the presence of independent regulations since this limits government opportunism and independent regulation strategically affects the interaction in price levels and investments.

3.5.1. Regulating to Promote Infrastructure Investments

How do we use regulations to attract infrastructure investments into the nascent gas industry in Ghana? Infrastructure investment decisions in energy networks are strongly influenced by regulatory frameworks and institutional arrangement (Cullmann and Nieswand, 2015). Eberhard (2006) stated the aim

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[23] Economic regulation refers to government impose restrictions on firms' decisions through the control of price or quantity or control of entry or exit or the combination of them (Bhattacharyya, 2011).

[24] Regulatory substance is the content of regulation, the "what" of regulations, which involves decisions about tariff levels and structures, cost mechanism, investments obligations (Gencer et al., 2006).

[25] Regulatory governance refers to the institutional and legal design of the regulatory system, the "how" of regulation, which involves decisions about the independence of the regulator (Gencer et al., 2006).

of regulations in these nascent markets is to encourage efficient, low-cost, and reliable service provision while ensuring financial viability and attracting new infrastructure investments.

How can regulation incentivise the appropriate balance for lower prices to consumers and provide incentives for infrastructure investments? The regulatory concerns in Ghana are targeted at providing appropriate tariffs for both consumers and investors. (Berg, 2001; Gencer et al., 2006; Cambini and Rondi, 2010; Poundineh and Jamasb, 2013; Jamison et al., 2014), identified the concept of combining economic regulation with an independent regulator as a panacea for addressing the problem of providing appropriate tariffs and attracting investment. (Bhattacharyya, 2011) noted that, there are two main types of economic regulations: rate-of-return and incentive regulations.

3.5.2. Rate-of-return Regulations

Rate-of-return is the income which investors are allowed to earn per unit of investments (Bhattacharyya, 2011). This rate-of-return allows the investor to recover its cost, guarantees investors fixed return on investments and reduce regulatory risk but fewer incentives to improve productive efficiency (Egert, 2009; Cambini and Rondi, 2010). The allowed rate-of-return on the ceiling capital can lead to overinvestments (Cullmann and Nieswand, 2015).

Egert (2009) noticed that this may actually lead to under-investment due to allocative inefficiency i.e. the Averch-Johnson effect, because the guaranteed rate-of-return is higher than the market interest rate, companies have the incentives to utilise more capital input and less labour which causes inefficient allocation of resources and overinvestments and lead to price distortions (Vogelsand, 2001; von Hirschausen, 2008).

Vogelsand (2001) and Egert (2009) argue that rate-of-return regulations do not allow for industry structural changes in the transition from VIM/SBM to MBM/competition, as the tendency of over-investment and the issue of excess capacity may be used as a strategic tool to limit competition. Alternative regulations such as incentive regulations offer structural transitions, incentives for investments and efficiency improvements.

3.5.3. Incentive Regulations

The concern is how incentive regulation is used to attract and sustain infrastructure investments. Incentive regulations use rewards and penalties to induce utilities to achieve desired goals where the utility is afforded some discretion in achieving such goals (Bhattacharyya, 2011). The regulator rewards outcomes and controls less of behaviour (Vogelsand, 2001). Incentive regulations follow two principles: Competition is preferred to regulations and regulations should emulate competitive outcomes (Bhattacharyya, 2011). Incentive regulation provides the platform to transit fully to a competitive structure because it provides flexibility (Vogelsand, 2001).

Poundineh and Jamasb (2013) analysed the relationship between incentive regulations, infrastructure investment and efficiency improvement. This relation requires a rebalancing of different incentive regulatory mechanisms. Incentive regulations improve efficiency and efficiency improvements attract more investments. Infrastructure investment rates are higher and productive efficiency improves under incentive regulations compared to rate-of-return regulations (Cambini and Rondi, 2010).

Empirical evidence indicates that incentive regulation has a positive effect on infrastructure investments and if implemented with an independent regulator leads to higher infrastructure investments (Egert, 2009; Cullmann and Nieswand, 2015). Incentive regulations should be implemented within a coherent regulatory framework with an independent regulator to support infrastructure investment (Egert, 2009). However, Joskow (2008) opined that incentive regulation implementation requires a large amount of information from the regulated utilities in capital accounting, capital cost and expenses, cost reporting protocols, data collection and reporting requirements for dimensions of performance, comprehensive rate cases and price reviews and relevant incentive mechanisms determined. This information asymmetry presents a challenge to nascent industries to implement incentive regulations effectively.

Incentive regulations can take two generic forms: individual incentive and yardstick regulations. In individual incentive regulations, the regulator will regulate the utility based on some of its observable measures and other alternative regulatory mechanisms are, price cap regulations, revenue cap regulations, targeted incentives, sliding scale, menu of contracts and partial cost adjustments (Bhattacharyya, 2011; Jamasb and Pollit, 2007). The main challenge in regulations in the nascent gas industry in Ghana is setting prices and tariffs and price cap regulation ensures pricing efficiency.

3.5.4. Price Cap Regulations

Price cap regulation is defined as the index of the regulated service that is adjusted on an annual basis by the movement on general inflation (RPI), reference price, an X-factor that reflects efficiency improvement and a Y-factor that allows for pass-through of specific cost outside the control of the regulated utility (Vogelsand, 2001; Khalfallah, 2013). The initial rates under a price cap regulation are typically set based on the traditional rate of return regulations but subsequent changes are made automatically by using a set formula adjusted annually (Bhattacharyya, 2011).

Price cap displays two main regulatory benefits: incentives for cost reduction and incentive and freedom for price rebalancing which are the main concerns of regulation in the nascent gas industry in Ghana. Two commonly used price indices are the retail price index (RPI-X) and the consumer price index (CPI-X).

Price cap regulations are simple and flexible to use and implement (Vogelsang, 2001): they offer incentives to investors and consumers, reduction in regulatory intervention and micromanagement possibility and greater price certainty. Price cap regulations are consistent with the implementation of a competitive market structure and can accommodate gradual deregulation transition (Vogelsand, 2001). They can maintain cost-reducing incentives and improve on allocative efficiency compared to rate-of-return regulations.

However, price cap regulations are subject to manipulations, turn to lead to bad welfare outcomes, and may require ex post adjustments (Vogelsand, 2001). The argument on allocative inefficiency holds as it leads to lower productive efficiency; and finally, they do not provide a guaranteed return on investments as RoR regulations (Bortolotti et al., 2007; Bhattacharya, 2011). Joskow (2008) recognised that price cap regulations increase regulatory uncertainty for investors, which according to Egert (2009) can lead to under-investment. Regulatory uncertainty does not only result in under-investment but may change the structure of investment, where the investor's chances of attracting finances may decrease resulting in future financial distress. However, regulatory uncertainty as Egert (2009) maintains can be mitigated by introducing the concept of an independent regulator.

3.5.5. Designing Appropriate Incentive Regulations

The tailor-made regulatory structure which Vogesland (2010) suggested for network industries is recommended for the nascent gas industry in Ghana, which involves the combination of rate-of-return and incentive regulation. Khalfallah (2013) suggested a hybrid approach of regulation where rate-of-return is combined with incentive regulations. Therefore, information on CAPEX is obtained from rate-of-return regulations with specific adjustment mechanisms that prevent overinvestment. OPEX information is obtained from incentive regulation to shift some operating cost to investment cost. Price cap under incentive regulation will regulate OPEX and rate-of-return for CAPEX.

Khalfallah (2013) concluded that, while there is no single dominant regulatory approach that can be used to attract and sustain infrastructure investment and provide appropriate tariffs, a much more efficient regulatory system for such a purpose will be a sum of complementary regulatory tools. Price cap regulation is used as the central regime to reach cost and price efficiency. It is adjusted to include additional regulatory schemes to address other regulatory objectives beyond investments and tariffs.

3.6.0. Regulatory Governance and Institutional Arrangements

Regulatory governance is the legal design of the regulatory system, institutional arrangements and the processes of regulatory decision making and infusing order (Williamson, 2010). Institutional arrangements are required to reorganise structural and regulatory institutions. Effective regulation is the function of governance mechanisms that frame and give rise to sound regulations and policies (Sovacool and Jarvis, 2011).

The regulatory framework needs to be supplemented by governance and institutional arrangements, which are essential for gaining the social license to operate (Vivoda and Cornish, 2016). The independent regulatory model is recommended in regulatory governance (Gencer et al., 2006). Jamasb and Polllit (2007) posited that independent regulation has become the pre-requisite and cornerstone of reform of infrastructure investments in network industries.

What is an independent regulator? This is when the regulatory body makes decisions without the prior approval of any other government entity and no entity other than the court or a pre-established appellate panel can over-rule the decision (Gnecer et al., 2006). The institutional building blocks of an independent regulator are organisational independence, financial independence and management independence (Gnecer et al., 2006). The Meta or higher order principles that governed the independent regulator include credibility, legitimacy and transparency (Gencer et al., 2006).

In fragile and weak states where regulatory capacity, commitment, or both are limited; there is considerable scope for developing transitional regulatory systems. Although not having all the elements of the independent regulator, there should be good dynamic properties (Gencer et al., 2006). These transitional models should be able to provide better incentives and pressure to move to full independent regulations.

Estache (1997) and Gencer et al. (2006) recognised that for regulatory governance effectiveness and independence in the utilities sector ten principles have to be implemented; Independence, Accountability, Transparency, Predictability, Clarity of Roles, Completeness, Proportionality, Requisite Powers, Appropriate institutional characteristics and Integrity.

3.6.1. Developing Effective Infrastructure Regulatory Framework

The ultimate aim of the regulatory governance system should be targeted at achieving an effective regulatory framework, which transparently provides investors with credible commitments and consumers with genuine protection (Gencer et al., 2006). An effective regulatory system should be able to deliver important sector outcomes such as an increase in capital investments, adequate price levels, improved service quality, consumer satisfaction, profitability, productivity gains, expansion of basic services, subsidies to reach the very poor, and the functioning of markets (Gencer et al., 2006).

An effective regulatory system for infrastructure investments consist of the following; a legal framework where the regulatory agency is created based on a prospective law that fully articulates its jurisdictional authority, powers, duties and responsibilities. Legal powers to make final decisions within its statutory domain in setting tariffs and standards, rules and policies, prevent monopoly, promote competition, and protect consumers from unfair abuse.

Financing of regulatory agencies: the level of financing for the agency should be maintained by law and should be adequate for the regulatory agency to meet its responsibilities competently and professionally in a timely manner. Regulatory accountability: the legislative committees or relevant ministries should subject regulatory agencies to periodic management audits and other types of effectiveness and performance reviews of the regulatory agencies.

3.6.2. Regulatory Risk

Investors in infrastructure in developing countries usually complain of regulatory risk and this is the potential loss of regulated revenues resulting from arbitrary changes to an agreed or pre-specified legal framework governing infrastructure investments. This could result from the idiosyncratic application of rules (Eberhard, 2006). Regulatory risk is mitigated through improved governance and Partial Risk Guarantees (PRG).

The first PRG is a US$5million from the World Bank, a 20-year Utility concession in Uganda in 2004, to support a potential loss of regulated revenues resulting from a “guaranteed event”, based on pre-defined loss-of-revenues formulae. The PRG provided liquidity during a period of distress in network infrastructure expansion and additional network investments (Eberhard, 2006). Second, is the Ghana Sankofa Gas Project in 2015 involving the government, ENI-Ghana and World Bank of record investments of US$7.9billion to underpin a US$8billion of gas-to-power infrastructure investments (World Bank, 2015).

3.7.0. Chapter Summary

There is a relationship between industry structuring, independent regulation, and Infrastructure investment. VIM/SBM are been replaced with MBM/competitive structures so as traditional regulatory models of rate-of-return are replaced with incentive regulations. Regulatory commitments in regulatory independence are one of the most important features influencing infrastructure investments. This study is viewing industry structuring through transiting from VIM/SBM to MBM/competitive markets, independent and incentive regulations in infrastructure investments and business viability of gas supply from the perspective of the nascent gas industry of Ghana.

CHAPTER FOUR
METHODOLOGY

4.0. Introduction

Chapter four presents the methods used to undertake the research. It is organised as follows: the first section provides details on the analytical framework and how it is developed. The next section describes the stakeholder consultation interviews and the procedures involved, and the final section describes the integrated cash flow model.

The research methodology is a way to systematically solve a research problem. Analytical research method uses facts and information available to make analysis for critical evaluation purposes to solve a research problem (Creswell, 2012). The analytical research approach is an inductive research tool, which considers the cause-effect relationship in deterministic and stochastic phenomena (Kothari, 2004).

4.1.0. The Analytical Framework for the Gas Industry in Ghana

The methodology of the study develops an analytical framework based on an integrated cash-flow model, which systematically analyses issues in the gas-to-power sector in Ghana. The analytical framework incorporates technical, economic and policy issues in building an integrated gas-to-power industry. The integrated cash-flow model is used to undertake business viability and risk analysis in gas-to-power development. Two theories: Structure-Conduct-Performance (SCP) paradigm and the Transaction Cost Economics (TCE) are combined to establish the interrelationship between industry structure, regulations and infrastructure investment decisions in the nascent gas industry in Ghana. Stakeholder consultation through semi-structured guided interviews is included to collect primary data from the gas industry for the analysis.

The integrated cash-flow model develops an Excel-based spreadsheet of the various supply components of the gas industry chain to determine their business viability for risk identification and enhanced competitiveness. Simulation and sensitivity analysis are performed on the integrated gas value chain to identify the various risk variables affecting their viability and mitigation measures suggested.

This study combines the analytical framework built on the solid theoretical background of SCP and TCE to provide analysis on structure and regulations. It, also, develops an integrated cash flow model to undertake business viability, simulation and sensitivity analysis for opportunities and enhance the competitiveness of the nascent gas industry in Ghana. The rest of the study explains how the analytical framework and the integrated cash flow model are developed.

4.1.1. Developing the Analytical Framework

The analytical framework combines the SCP paradigm and TCE theories. The SCP paradigm establishes the interrelationship between industry structure, regulations and infrastructure investment decisions in gas-to-power industries. TCE, on the other hand, provides the theoretical relationship between these three components. The application of this analytical framework is narrated in three phases as illustrated on Figure 6.

SCP is used to provide an evaluation model from the perspective of gas-to-power development to evaluate the performance of industrial organisation and regulations and attract infrastructure investments (Peng and Poundineh, 2017). The SCP framework offers a dynamically complex system of interlocking decisions made by government, firms and major stakeholders. The framework unites industry structure, regulations, governance and investment decisions. The SCP framework makes the following claims:

- The ownership structure of the industry influences regulations.
- The use of infrastructure is constrained by the capacity of the infrastructure available.
- The continuous interactions between industry structure, regulations and investments decisions determine activities in the industry.
- Governmental regulation or industry self-regulation?
- Multidimensional and evolving nature of the interrelationship.
- Hybrid nature of sector ownership in many developing countries

From Table 23, ownership of infrastructure dictates the structure and regulatory pattern in the gas industry. Infrastructure ownership and operations determine the structure and regulations of the industry. The government and its agencies are the regulators, and at these early stages, government is the main infrastructure investor. The heavy government ownership of infrastructure and investments which dictate vertical integration and centralised ownership and direct government regulations. Limited private investments mean higher government ownership and control.

Table 23: The SCRP in three dimension

Key Agents	**Structure**	**Regulations**	**Infrastructure Investments**
Industry Players	Exogenous: regulatory regime Endogenous: Own infrastructure	Direct regulations through ownership control	Own and operate infrastructure
Government and its agencies	Sector regulation regime and main infrastructure investors	Indirect regulations through performance by exercising regulatory authority constraints by sector regulatory regime. Direct regulations of own performance through ownership control	Implementation of new sector regulatory regime increases own regulatory capacity and influences goals of agents in other dimensions through authority own and operate infrastructure
Interest Groups e.g. Investors	Structural framework and regulatory regime	Indirect regulation of industry structure and infrastructure usage influences investments. Direct regulations of sector performance through ownership control	Sector performance perceived relative to interest groups.

Source: Adapted from Peng and Poundineh (2017).

As private sectors investments in infrastructure ownership increases, there are now several interest groups in the industry, mostly government, investors and other key industry players. There will be structural and regulatory constraints requiring interventions. Regulations influence the goals of agents in the industry through control and infrastructure operations and self-regulation, and the government indirectly steers the industry through economic regulations.

Centralisation allows only state-ownership of infrastructure but decentralisation allows private ownership of infrastructure. If the industry structure encourages decentralisation and promotes private participation, regulations and governance arrangements would be designed in such regards and infrastructure investment decisions can be influenced positively or negatively. At a nascent stage where infrastructure is lacking, a combination of both state and private ownership of infrastructure can be formulated.

Regulation of gas facilities such as the transmission network and storage facilities requires Third Party Access, tariff regulations and legal/functional unbundling. The absence of independent regulations will require that differences relating to institutional, administrative and governance are properly resolved. An independent regulator will, be able to resolve this issue.

Under the centralised structure, the state utilities are responsible for all investment decisions: planning new investments and expanding existing ones. In most cases, the approval of the national regulator is needed. Cost recovery is integrated into the overall electricity tariff payable by end-users. Under the decentralised structure, however, the network segment is unbundled and infrastructure ownership is dispersed between a number of companies licensed to own and operate the infrastructure. The owner's plan for network infrastructure investments needs to be approved by the regulator and the value of investment is recovered via regulated tariffs payable by end-users of the network with full cost recovery.

The SCP paradigm establishes the interrelationship between structure, regulations and infrastructure investments decisions in the nascent gas industry. The proposed SCP framework informed the formulation of questions in the semi-structured guided interviews. TCE, on the other hand, is used to determine industry behaviour and provide guiding principles for structuring, regulations and investment decisions (Spanjer, 2008). TCE considers the alternative governance structures and their competencies (Pratten, 1997), and vertical integration is the focal point of analysis for industry structure (Williamson, 2010). However, competitive structures are alternative governance arrangements, which generate efficient outcomes (Pratten, 1997).

In vertically regulated structures, government opportunism may present a source of risk to investors and to public organisations, which generally leads to inefficiencies (Spiller, 2013). Regulatory rules such as incentive regulations (price caps, incentive schemes, and use of competition) may generate flexibility, which reduces risk and may lead to higher investments. Investors also require appropriate institutional arrangements and safeguards to be prevented from government opportunism. This suggests an appropriate regulatory framework, which includes price setting, conflict resolution procedures, investment policies, quality control and sunk cost recovery (Spiller, 2013).

Infrastructure investments in the gas industry can be viewed from the perspective of TCE. That is, long-term, asset specific investments require heavy capital and face several uncertainties (Jin and Doloi, 2007). Government alone cannot provide the entire infrastructure; the private investors usually supplement. The major challenges hindering private investors are the uncertainty of cost recovery and making a return on their investments. This uncertainty is a component of TCE (Chiles and McMackin, 1996) which may arise from changes in the exogenous disturbances (external environment) or behavioural changes affecting the system (Willaimson, 2010; Jin and Doloi, 2007) as indicated on Table 23.

In a situation where the infrastructure is highly specific with dedicated ownership and unified contracts, there is a rare frequency of transactions or the transactions are between few players with simple transactions where vertical integration with governmental regulations are common. Uncertainties at this stage are minimal but government opportunism in meeting its objectives is high. In this condition of vertical integration with government, regulations are sufficient to maintain efficient industry performances.

Investors are concerned with cost recovery and return on investments from the regulated tariffs as uncertainty levels are moving towards intermediate levels. Cost recovery and efficiency regulations are required to attract and sustain infrastructure investors. At this stage, the regulatory mechanism will require modifications to reflect the needs of the industry in addition to a dedicated regulator. An independent regulator with appropriate institutional and governance setting is required. The contribution of the SCP and TCE theories to the study methodology formulation is as follows:

- The analytical framework provides a holistic view of the gas industry.
- SCPR provided leading questions in structural, regulatory and investment decisions, which are used to develop the semi-structured questionnaires in the stakeholder consultations.

The theoretical review provided some questions, which serve as the basis for developing the questionnaires during the stakeholder consultations from the three objectives of the study:

Industry Structure: to what extent does the ownership/operational control of the components of the gas industry impact on development? How is the current structure supporting industry operations? Who owns what, operates where and how? What is the appropriate industry structure for Ghana? To what extent does ownership/operational control in the gas sector overlap? What are the implications of such overlaps on regulations and investment decisions?

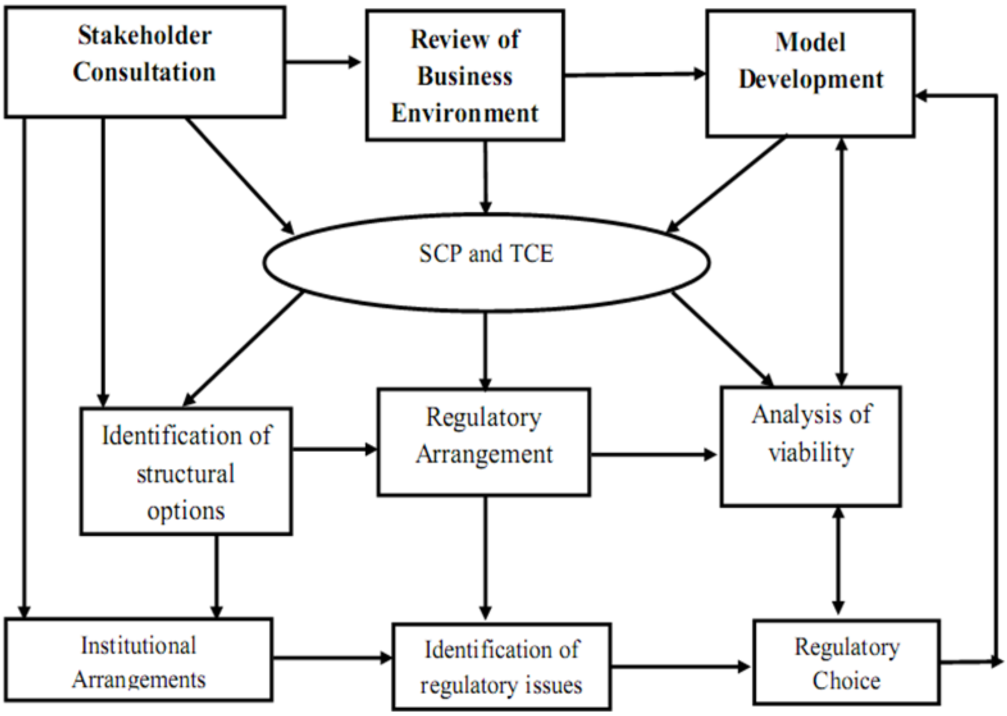
Infrastructure Investment Decisions: what is the state of the gas industry infrastructure? What are the infrastructure requirements? What could be the potential risk and mitigations measures for investors? Which segments of the gas industry are viable for business? In addition, how sensitive are the most variable risk factors (e.g. prices, volumes, cost and others)? What is the state of gas-to-power infrastructure in the industry? What could be the potential implication of absolute and relative use or substitution between gas and power?

Regulations and governance arrangements: what are the regulatory arrangements and measures affecting the industry? Are the regulatory measures adequate? What implication has regulation on infrastructure investment? Does the gas industry require its own laws and an act of Parliament? Are government energy policies related to the gas industry policy? Moreover, do power sector goals or gas sector goals or both drive them? How are government regulatory measures affecting the industry agents? What implications do they have for the gas sector planning?

The scheme on Figure 6 presents the analytical framework for the study of the gas industry in Ghana, which centres on the SCP and TCE theoretical framework. Stakeholder consultations with major players in the gas industry identified major challenges in the gas industry's business environment. As a result, an integrated cash flow model is developed to lead the discussions, which are used for the viability analysis of the supply components of the gas industry.

The top components (stakeholder consultation, review of business environment and the model development) influenced the choice of an all-encompassing theoretical framework (SCP and TCE) suited for analysing the interrelations between structure, regulations and investment decisions in the gas industry in Ghana. These two theories influence the choice of structures and identification of structural options for the nascent gas industry in Ghana. Stakeholder consultation, business environment analysis and the theoretical framework should inform the identification of industry structural options and regulatory arrangements for the gas industry in Ghana.

Figure 6: Analytical Framework of the gas industry in Ghana



Source: Adapted from Bhattacharya (2011).

The structural option and the regulatory arrangement identified should influence how institutions are to be arranged in the gas industry. The integrated cash flow model allows analysis of the business viability of the gas industry with input data from the stakeholder consultation and analysis based on the structure and regulatory arrangements and the SCP and TCE theories. A final specific regulatory choice is made for the gas industry in Ghana, which is informed by the feedback loop from the stakeholder consultation, business environment review and the integrated cash flow model development.

The questions from the SCP and TCE theoretical review are identified as qualitative data; they are open-ended questions. An interview guide through semi-structured interviews is designed in stakeholder's consultation to provide answers to the questions (Venables, 2016; Grindsted, 2005).

4.2.0. Stakeholder Semi-structured Guided Interviews

Semi-structured guided interviews are designed to allow subjective knowledge acquirement from persons regarding a particular reality they have experienced (Vinci et al., 2017; McIntosh and Morse, 2015). They provide the best methods for obtaining information on the motivation behind an entity's choices, attitudes and beliefs, impacts of specific policies or events (Raworth et al., 2012). The method employs a relatively detailed interview guide and it is used when there is sufficient objective knowledge about a phenomenon (McIntosh and Morse, 2015; Elo and Kyngas, 2007).

The semi-structured interviews are chosen in place of focus group discussions because it is difficult to bring together several organisations under one meeting schedule (Laforest, 2009). Questionnaires alone would not be able to give the detailed guided questions and answers from the analytical framework on Figure 6 and the number of questionnaires needed to meet a standardised research would not be met due to the limited number of participants (McIntosh and Morse, 2015).

Semi-structured interviews provide simple and flexible questioning in addition to less imposing and more neutral and spontaneous data gathering tools required for gathering structural, regulatory and investments decisions information. The interviewer refraining from evaluating comments, restricting reactions to minimal responses and acting "neutral" during the interview easily manages interviewer bias (Wood et al., 2016; Grindsted, 2005).

4.2.1. Sampling

The sample size for data adequacy for semi-structured interviews must be guided by the following principles to ensure data adequacy (McIntosh and Morse, 2015). The semi-structured guided interviews answer the questions from the SCP and TCE framework, which as well provide numerical data for the integrated cash flow model to develop the analytical framework. Hence, a fair representation of respondents is required (Laforest, 2009).

A sample size of 10-30 participants is recommended in performing non-parametric statistical analysis since a meaningful parametric statistical analysis requires a minimum of 10 participants (McIntosh and Morse, 2015). The instrument is, thus, used to collect data from eight (8) governmental and five (5) private companies engaged in the gas industry value chain in Ghana. Stakeholder individual respondents in their various organisations were identified based on their specific roles and direct participation in the gas industry as either state institutions or private infrastructure investors. The stakeholders are categorised into upstream, midstream, downstream and regulatory agencies and private companies to represent the full range of the components of the gas industry as indicated on Table 24. These companies are identified by their sectors of operations and the codes used to refer to the interviewees in subsequent chapters are described.

At least each of the segment is represented by an organisation. For example, GNPC and ENI-Ghana were selected for the upstream because GNPC is the national oil company involved in all oil and gas contracts with IOCs and acts as the national gas aggregator. ENI-Ghana is an IOC focused on non-associated gas production as compared to Tullow Plc, Kosmos Energy, Anardarko, and Hess, which focus on crude oil production. In the midstream, Ghana National Gas Company Limited (GNGC) processes and transmits gas from the processing plant at Atuabu (Western Region) to thermal plants in the same region. WAGPCo is engaged in the transmission of gas from Nigeria to Ghana and provides a valuable contribution in private operation.

In the downstream segment, there are four Independent Power Producers (IPP) using gas as a part of a stream of fuels or as the only fuel for their thermal plants operations. These are the Takoradi International Company (T1 and T2) which are operating under the Volta River Authority (VRA), the state utility company, Sunon-Asogli Power Plant (SAPP), and Asian-Middle East Resources and Investments (AMERI) Power Plant. Three of the four IPPs were interviewed (T1, T2, and SAPP). It was difficult interviewing AMERI due to the political hype and media attention it attracted on the contractual arrangements. There are other IPPs such as Karpower and CENIT, Emergency Power Barges, which do not use gas but light crude oil, heavy oil or distillate oil for electricity generation.

Table 24: Semi-structured guided Interviews Organisations

State Institutions	Activities	Sector/Code	Date of Interview
Ministry of Energy	Energy sector policy formulators	Min-Energy	19 April, 2016
Ghana National Petroleum Corporation	Upstream natural gas aggregator	Upstream-GNPC	30 April, 2016
Ghana National Gas Company	Midstream natural gas processing	Midstream-GNGC	17 May, 2016
Bulk Oil Storage and Distribution Company	Midstream natural gas transportation	Midstream-BOST	6 April, 2016
Public Utilities Regulatory Commission	Economic/Financial Regulator	Downstream-PURC	19 April, 2016
Energy Commission	Midstream technical regulator	Midstream-EC	7 April, 2016
Petroleum Commission	Upstream petroleum regulator	Upstream-PC	6th April, 2016
Volta River Authority	Downstream gas consumer/Power producer	Downstream-VRA	6 May, 2016
Private Institutions			
ENI-Ghana	International Oil Company-Operators of SGP	IOC-ENI	4 May, 2016
West African Gas Pipeline Company	Midstream transnational gas transmission	Midstream-WAGPCo	3 May, 2016
Takoradi International Company (TICO)	Downstream-IPP	TICO-IPP	6 May, 2016
Takoradi Thermal Plant Station	Downstream-IPP	TAPCO-IPP	7 May, 2016
Sunon-Asogli Power Plant	Downstream-IPP	SAPP-IPP	9 January, 2017

Source: Data from Interviews.

4.2.2. Procedures for Conducting the Semi-structured Interviews

The procedures started with a study plan; that is, conceptualising the sort of information required from the stakeholders based on the analytical framework and questions raised from the SCP and TCE framework for analysing the nascent gas industry in Ghana. Planning the interview sessions and visiting the various companies with Consent Forms for their consent and statement of willingness to participate in the interviews were next. Eight government agencies agreed to participate in the interviews and gave their consent. Three IPPs using natural gas as fuel and two private entities (ENI-Ghana and WAGPCo), also, gave their consent. In total thirteen organizations agreed and gave their consent to participate in the interviews (see Appendix 1 for sample of consent form).

The interview questions were taken through a pre-test (pilot study) with three selected companies within the three segments of the gas industry including upstream, midstream and downstream. The pilot study companies were mostly state institutions which validated, refined questions, estimate interview durations, obtain clarity and feedback on using the semi-structured interview and reformulating the questionnaires (Vinci et al., 2017 and Wood et al., 2016). The pilot study also revealed that an authorization letter from the Ministry of Energy and De Montfort University would indicate authentication for the research. As a result, letter from the Ministry of Energy is obtained as an introductory letter during the interviews (see Appendix 2).

The pilot study led to the modification of the interview schedule; thus, grouping it into three sections based on the study objectives and analytical framework: industry structure, regulations, governance arrangements, and infrastructure investments decisions. The introductory letters also serve as point of reference and authorization for the conduct of the main interviews.

The interviews usually lasted an average of fifty minutes (50). The various companies chose the individuals to be interviewed based on their knowledge and experience in the gas industry and their ability to answer the questions. Open-ended questions are asked as indicated on the Boxes 4, 5 and 6. The interview commences with the introduction of the purpose, signing of a second consent form, which indicates their acceptance to be interviewed, and seeking permission for audio recording. The audio recording provided a reliable means to transcribe the interview (Vinci et al., 2017).

At the end of each interview and transcription, the interview was evaluated using the evaluation criteria suggested by Vinci et al. (2017). These include verification of questions asked during the interview in comparison with the questions on the interview schedule plan to ascertain their convergence and to verify whether there were disagreements or complementarity in each question asked. During the interviews, questions were rephrased, adapted to suit the condition of the industry players and to reflect the understanding of the player and the segment of operation. At the end of the validation process, the questions in Boxes 4, 5 and 6 were used as the main interview guide. Nevertheless, each industry player, depending on the segment of operation, is asked specific questions that pertain to their main operations. General questions were asked as well. However, some of the industry players such as GNPC, VRA and ENI have involvements in all the segments; hence, they were given more attention.

Box 4: Questions on the Structure of the Natural Gas Industry

Section 1: Structure of the natural gas industry in Ghana

a. Which segment of the natural gas industry do you operate?

b. How would you describe the current structure of the gas industry? What problems do the current structure pose to your investment? How should the industry be restructured/structure redefined? What possible industry structure do you recommend? How is the current gas industry structure contributing to your performance?

c. Upstream Operations: Why should upstream production and supply of gas in Ghana be dominated by state-monopolies? Why should one company be allowed to operate the entire value chain of gas-to-power generation? What are your views on the current structure of the Gas Processing Plant (GPP)?

d. Transmission Pipelines: what are your views on industry structure of gas transmission? How can the government play a role in the pipeline transmission of gas? What are the conflicting roles between the major pipeline companies in Ghana? How are gas transmission tariffs determined? Are they competitive to promote further investments?

Box 5: Questions on the Business Viability of the Supply Components

Section 2: Infrastructure Investment and Business Viability

a. Identify the infrastructure requirements for the gas industry in Ghana, identify business opportunities in the industry, and identify the risks your organisation faces in the industry and suggest any mitigation measures.

b. What are your major investment obstacles in the industry? Are you satisfied with the current structure of the industry? Are you satisfied with current regulatory activities in the industry? How are your operations affected by the structure and regulations of the gas industry in Ghana?

c. What is the best investment environment for you? What should be done to provide the best investment environment for your future infrastructure investment? What should be done to enable full cost recovery and sufficient return of your investments from natural gas prices?

Box 6: Questions on Regulation and Governance Arrangements

Section 3: Regulatory Arrangements of the natural gas industry in Ghana

a. Upstream: Is there any regulatory framework for upstream production of gas? Are there specific regulatory requirements for gas production? Do we require any upstream gas production regulatory framework for Ghana? How is the regulatory mechanism working?
b. Midstream: Is there any regulatory framework for pipeline transmission activities? How is the regulatory framework for pipeline transmission of gas working? How is the current regulatory framework contributing to your performance?
c. Downstream: Do we have a regulatory framework governing the use of gas for electricity generation? How is the regulatory framework working in support of your investment cost recovery? What should be factored in the pricing of gas for electricity generation?

4.2.3. Stakeholder Semi-structured Guided Interview Data Analysis

The aim of the stakeholder interviews in this study is to elicit and ascertain stakeholders' perspectives to confirm, correct, or discover new knowledge pertaining to the nascent gas industry in Ghana (McIntosh and Morse, 2015). Analysis from the interviews are designed to provide a comprehensive and accurate descriptive summary of participants' perspectives and to lead arguments in the analysis. The data analyses procedure include preparing the data for analysis and conducting content analyses. The three main forms of analysis of semi-structured interviews are content analysis, discourse analysis and hermeneutic analysis (Vinci et al., 2017). This study adopts content and discourse analysis, which started out with organisation and transcription of data obtained, identification and coding of statements made using NVivo, outlying of statements made from the study objectives; analysis and clarification of obtained and coded terms and summary of findings (Vinci et al., 2017).

The transcribed data were converted into a PDF document, embedded into the NVivo software version QSR11, coded into various themes and sub-themes and analysed. The outcome was used to lead arguments and discussions in Chapters 5 and 7. Some of the answers and data obtained (e.g. prices, production volumes, discount rate and others) from the interviews are also added to the integrated cash flow model in Chapter 6 to develop a more accurate and robust analytical framework which reflects industry activities.

4.3.0. Integrated Value Chain Analysis

The risk intrinsic to natural gas industries in developing countries makes it necessary to develop an integrated value chain, which links exploration and production, processing, transmission and consumption as a complete system. Although IOCs oil production is linked to gas production, gas production is peculiar to an exclusively linked pipeline transportation to specific consumers with high initial fixed cost and consumption limited to a particular location, unlike oil, which is a global product (Herath and Malhotra, 1996).

While most cash flow studies are concerned with modelling Production Sharing Contracts (e.g. Kasriel and Wood, 2014) and power plants economics separately (e.g. Razavi, 2007), Herath and Malhotra (1996) modelled gas exploration and production, transmission and power generation as an integrated system. Their integrated cash flow model has three main objectives. First, to demonstrate the need to analyse gas projects as an integrated system; second, to describe an integrated cash flow approach for gas projects which can be used to determine the returns to different parties under different parameters and perform sensitivity analysis and finally, to provide a practical tool to help governments negotiate gas contracts.

Ibata (2009) extended the integrated cash flow model in a Ph.D. thesis to ascertain the economic viability of gas supply and the economic analysis of alternative natural gas uses in DR. Congo. The integrated cash flow model was used to demonstrate that in DR. Congo gas to power generation is economically viable. However, associated natural gas to power generation was identified as economically viable due to lower upstream gas prices. Non-associated gas-to-power generation will require government subsidy to remain viable and should be competitive to hydropower.

This study's methodology will adapt the integrated cash flow model of Herath and Malhorah, (1996) extended by Ibata's (2009) DR. Congo gas-to-power analysis to examine the business viability of the supply components of the gas industry value chain in Ghana. This is achieved through developing an integrated cash flow model and performing simulation and sensitivity analysis to provide a practical risk identification and mitigation tool for the nascent gas industry in Ghana.

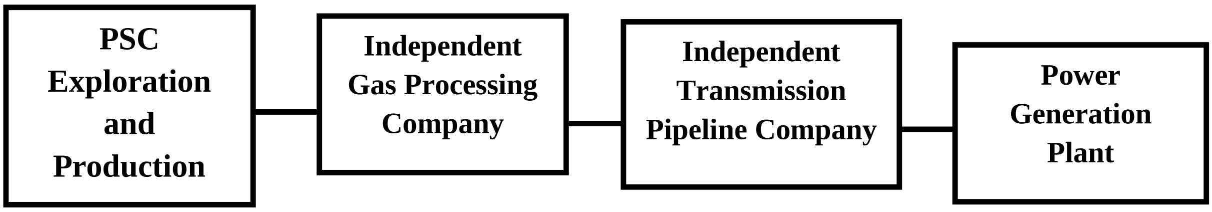
The advantage of considering the gas industry within the fulcrum of an integrated cash flow model instead of mutually exclusive components is the ability to analyse the impact of Production Sharing Contracts (PSC) terms, processing and transmission tariffs and power generation profitability on electricity tariffs. The cash flow model is used to determine the business viability of natural gas exploration and production, processing and transmission and power generation, determining the negotiating boundaries for gas prices and PSC terms in Ghana's nascent gas industry.

4.3.1. Integrated Gas-to-power Value Chain Analysis

Natural gas integrated value chain analyses consist of activities related to exploration and production of natural gas, its transportation from the wellhead to a processing plant, then through the transmission pipelines to end users in the gas market. The initial consideration is usually given to the type of contracts signed, as indicated on Figure 7. This is either Production Sharing Contracts (PSC) or Joint Venture Agreement or Hybrid Contracts. The next component of the system is the processing and the transportation companies, which are usually independent companies.

The final component in the integrated system is the consumer, either a thermal power plant or ammonia/fertilizer plant, Aluminium plant, Mining Companies, Medium to Small-Scale Industries or LNG for exports if reserve volumes are sufficient. Emos Consultancy (2010) envisaged the use of natural gas as a source of raw material or source of generating power for the industrialisation roadmap of Ghana. The salt industry, the bauxite industry, the lime industry, manganese, iron ore and the gold mining industries provide alternative large-scale consumers for the commercialisation of gas resource in Ghana.

Figure 7: The Integrated Gas Value Chain in Ghana



Source: Adapted from Herath & Malhotra (1996).

Herath and Malhotra (1996) noted that a necessary condition for the long-term stability of the integrated natural gas chain for electricity generation is that it should be competitive with the other alternative uses and alternative fuels. Elements of the project components have to be viable in the supply of gas to the endpoint of the project and must be cost competitive compared to the alternative fuels such as coal, or imported gas, distillate fuel oil or Light Crude Oil (LCO). For the development of LNG for export, the project must be competitive with current LNG export prices and capital cost. There should be a receiving country willing to provide guaranteed investments. In addition, as feedstock to petrochemical industry or usage to other industrial consumers such as a fertilizer plant, the end product must be competitive with current domestic and international market conditions and project economics, possible alternative product sources and services.

The government is involved in the gas chain decisions making processes in terms of fiscal policy, energy policy, ownership, loan guarantees and impact on balance of payments and developing a legal framework for contracts. The government has the capacity to influence the business viability of the gas value chain, a critical component of the integrated chain is to design appropriate form and government interventions (Herath and Malhotra, 1996).

Box 7: Features of the Integrated Gas Chain in Ghana

- Long and firm chain
- Physically fixed links from well-head to power consumers
- Upstream production is dominated by IOCs
- Single natural gas aggregator upstream - GNPC
- Two major transmission pipeline networks (GNGC and WAGPCo)
- One natural Gas Processing Plant (GPP) (GNGC)
- Interruption in upstream affect downstream and vice versa
- High capital investment along the chain
- Downstream consumption is dominated by power plants (VRA)
- The industry is dynamic and subject to modification
- There are huge investments from Ghana Government and IOCs

4.4.0. The Integrated Cash Flow Model for the Gas Value Chain

The Integrated cash flow model for the natural gas industry is a simple spreadsheet consisting of four cash flow models: upstream production project (PSC), the gas processing plant, transmission pipeline network and the power plant consumers interconnected by their pricing and fiscal relationships as indicated on Figure 7. The link between upstream and the processing plant is the wellhead price of gas while the link between the transmission pipeline and power generating companies is the selling price of gas.

Each of these activities is linked to government and investors through the fiscal relationships, production royalties, and processing and transmission charges. The impact of these costs, profits and fiscal interrelationships are reflected in the power tariffs to be charged from electricity consumers (Herath and Malhatro, 1996). While the integrated cash flow model for the natural gas chain cannot be used for optimisation analysis, which is not the focus of this study, it can be used to perform static business viability analysis, simulation and sensitivity analysis. The inputs for the model are relatively simple and consist of capital expenditures, operating costs, gas production data, initial set of gas prices, plant capacity, load factors, efficiency rate, heat rate and electricity tariffs for the power plant summarised in Table 25.

Once the data pertaining to the gas industry are inputted and the model is set up. It aims at providing output information of Net Present Values (NPV) for upstream gas production, NPV for the processing plant, NPV for the transmission pipeline and NPV for the combined cycle gas turbine (CCGT) which are used for simulation analysis. The risk factors identified are compared to the NPVs to run the correlation and sensitivity analysis.

Table 25: Input Build-up Cash Flow Model Table

Upstream Natural Gas Production PSC	**Natural Gas Processing Plant**	**Transmission Pipeline Company**	**Power Generating Plant**
Upstream Capital Cost (US$m)	Processing Plant Capital Cost (US$m)	Pipeline Capital Cost (US$m)	Plant Capacity (MW)
Upstream Operating Cost (US$m)	Processing Plant Operating Cost (US$m)	Pipeline Operating Cost (%)	Capacity Cost (US$/kW)
Gas Production Volumes (bcf/year)	Natural Gas Receiving Volumes (BCF/year)	Pipeline Transmission Tariffs (US$/mm)	Plant Load Factor
Well-Head Price of Gas US$/mmbtu	Condensate Receiving Volumes		Efficiency Rate
Cost Gas (%)	Natural Gas and Condensate Processing Tariffs (US$/mm)		Heat Rate
Royalty, Profit Tax and Income Tax	Discount Rate, Inflation Rate and Rate of Return (%)		Operating Cost ($/kwh)
Discount Rate			Maintenance Cost (cents/kwh)
Cost Recovery % (CR)			Electricity price (US cents/kwh)
Profit Share Percentage (PS)			

Source: Herath and Malhotra, (1996).

4.4.1. Components of the Cash Flow Model

Kasriel and Wood (2014) developed an advanced integrated cash flow model using PSC terms modelled in Microsoft-Excel spreadsheet to provide an analytical framework that reflects the objectives of this study. The inputs for the model would have to be changed according to requirements of each country prior to carrying out the static, simulation and sensitivity analysis to determine negotiating boundaries for gas prices and PSC terms, which serve as the most important element for the gas industry (Herath & Malhotra, 1996). Discounted cash flows (NPVs) are calculated as follows (Kasriel and Wood, 2014):

a. Discount every year’s cash inflows (cash received, e.g. Revenues)
b. Discount every year’s cash outflows (cash spent, e.g. Costs)
c. Subtract each year’s (b) from (a) to get annual discounted net cash flow values and
d. Sum each year’s (c), to get net present value (NPVs), which is one of the most commonly used business viability valuation metrics in the petroleum industry.

The basic NPV decision rule is that investments, which have a positive NPV, are good investments, i.e. they are viable businesses. Those with negative NPVs, on the other hand, are considered not viable or high-risk projects requiring further risk analysis. From the NPVs generated, simulation is carried out using @RISK software to determine the level of viability. Sensitivity analysis are carried out on the most variable risk factors to determine which risk factor affects the viability of the projects.

Kasriel and Wood (2014) upstream PSC model is used to develop the first component of the integrated cash flow model for Ghana (Upstream Natural Gas Production) because of its robustness in building analytical frameworks for upstream gas/oil production.

Box 8: Definition of the Terms of the Cashflow model

- Gross revenue/field revenue are the production volume times the price. Here "*gross*" means before any deductions and sometimes the term "*net revenue*" is used to mean "*net of*" i.e. after the deduction of royalty and rate-of-return (ROR).
- Fiscal Outflows (Government Take): A bonus is a kind of fiscal payment made, often when some production milestone is reached e.g. Signature bonus paid when an agreement is executed. Rentals are periodic fees payable, based on the area of the license, and sometimes varying depending on what kind of activity (e.g., exploration, development or production) is occurring. Royalties are fiscal payments, which are usually calculated as some proportion of gross revenue (e.g. 15% or 17%). Income tax is payable as a percentage of taxable income, which is calculated as gross revenue less certain deductions or tax allowances. Field Outflows (IOC): CAPEX is capital expenditure. In this case, it is the cost of getting the field ready to produce by drilling wells and building infrastructure such as pipelines and processing facilities. OPEX is ongoing operating costs during the production years. (OPEX is sometimes incurred in the pre-production years, when CAPEX is being spent, consisting of things like administrative and managerial costs. Decommissioning costs are the cost of removing equipment, plugging wells and restoring production site after production ends.

  Source: (Kasriel and Wood, 2014).

4.4.2. Upstream Production Project: Sankofa Gas Project

In Production Sharing Contracts or Agreements (PSC/A) the IOC has a 100% equity interest in the oil and gas project and pays for all field costs. For instance, the Sankofa Gas Project has ENI-Ghana, the operators of the field, contributing 44.4% capital share, Vitol contributing 35.6% and GNPC, on behalf of the Government of Ghana, having a carried interest of 20%. ENI-

Ghana and Vitol account for 80% of the projects cost with GNPC given the opportunity to increase their participating interest in the future.

The upstream gas revenues are arrived at by multiplying gas production volumes by the wellhead price of gas. It is estimated on average 54BCF (which is the total reserve volumes of gas divided by the contract duration) of gas is produced annually from SGP sold at US$9.8/MMBtu. Royalties are the first to be deducted from the gas revenues. Full cost recovery is allowed whereby CAPEX and OPEX are deducted from the net gas revenues after royalties. The net income is then discounted to arrive at the net present values. The PSC specifies that a portion of net revenue, that is revenue after royalty deduction, will be the maximum amount available to the contractor to be reimbursed for designated field cost incurred. The portion of revenues the contractor receives as reimbursement is cost gas (Kasrial and Wood, 2014).

4.4.3. Contract Parties

Gas Production Sharing Contract (PSC) is a contractual agreement between two or more parties for the exploration and production of natural gas. The state automatically becomes one such party to the contract, with a state entity acting on its behalf such as the Ghana National Petroleum Corporation (GNPC) while the other party may be a single or a consortium of investors usually foreign companies (International Oil Companies) with experience, technology and financial stability (Kasrial and Wood, 2014). For the Sankofa Gas Project, ENI-Ghana and Vitol are the IOCs.

4.4.4. Contract Duration

PSC are long-term contracts usually for the full potential of the producible area. A typical PSC would be for about 20 years or more with the option to extend the contract required to enable any contractual obligations to be met. Due to the long-term nature of PSC, its utmost importance is for all parties to come to an agreement to reflect on the balance of commercial interest of all involved. The SGP, for instance, has an average duration of 20years.

4.4.5. Royalty

PSC includes a royalty payment to the government on natural gas produced, which could take several forms. For instance, a flat charge, a percentage of revenues or a sliding scale tied to the level of output. The advantage of a sliding scale is that it is progressive on higher prices and higher production and the government's take would increase in case of favourable developments (Kasrial and Wood, 2014). Royalties are a direct source of income to the government but should not be too excessive, as it would adversely affect the success of the project and provide no benefit to consumers since the gas is domestically consumed (Kasrial and Wood, 2014). The Government of Ghana takes 7.5% of gross revenues as royalty for gas production from the SGP.

4.4.6. Natural Gas Processing Plant (GPP)

The processing plant receives natural gas from upstream as their main input. The current installed capacity of the GPP is 150,000MMBtu/day. The key components of the processing plant include the capital cost, operations and maintenance cost. The link between the processing plant and upstream production of gas is the associated gas and condensates received for processing. The associated gas is then separated into lean/methane gas and other products such as ethane, propane, and butane together known as Liquefied Petroleum Gas (LPG). There is a processing tariff for methane gas to the operators of the GPP but the LPG is sold separately. The processing tariffs and LPG sales revenues are added together to arrive at the total sales revenues for the GPP. CAPEX and OPEX are deducted and the remaining net revenues are discounted to arrive at the net present value for the entire operation of the GPP.

4.4.7. Natural Gas Transmission Pipeline

The transmission pipeline receives lean/methane gas from the GPP and non-associated gas from the SGP through an Onshore Receiving Facility (ORF). Key components of the transmission pipeline include the capital, operation, maintenance cost, and transmitting tariffs. The link between the transmitting pipeline and the GPP are the methane/lean gas. The transmission tariffs for the GNGC pipeline is US$2.28/MMBtu.

Transmission volumes are multiplied by the transmission tariffs to arrive at gross revenues. CAPEX and OPEX are deducted from net income, which is discounted to arrive at the net present value of the transmission pipeline. Five percentage of the total gas volumes made available to the pipeline is assumed to be either used for the compressor station fuels or lost due to technical leakages and regarded as “unaccounted for gas” (Arpino et al., 2014).

In order to recover the investment cost for the processing plant, the transmission pipeline’s adequate processing and transmission tariff need to be charged. In doing this, the loan from the Chinese Development Bank for the construction of the GPP and the transmission pipeline with its interest repayments, recovering other capital and operations costs and getting a reasonable return should be considered. Both processing and transmission tariffs are determined by the economic regulator PURC in consultation with the infrastructure owners.

4.4.8. Combined Cycle Gas Thermal Power Plant

The CCGT is assumed to receive natural gas from the SGP through the GPP and the transmission pipeline for electricity generation. This is the last component of the integrated cash flow model. The cost components of the CCGT plant include capital cost, operations and maintenance cost, gas requirements, fuel cost, power generated and electricity tariffs. The CCGT plant is also assumed to have a capacity of 1100MW because the quantities of natural gas available for consumption per annum is on average 54BCF and it is a 1100MW plant which can fully utilise this gas as indicated on the integrated cash flow model (in Appendix 3). This could be a single plant or a multiple of plants totalling 1100MW. However, this study assumed that this is a single unit.

Table 26: Power Plant Assumptions

Assumptions	
Plant Capacity (MW)	1100
Capital Cost	950$/kW
Plant Cost US$ million	1615
Plant Life	25years
Plant Load Factor	90%
Plant Efficiency	48%
Heat Rate	7145BTU/kWh

Source: World Bank (2013).

The 1100MW plant will cost about US$1.045billion based on a capital cost of US$950/kW (World Bank, 2013). The operations and maintenance (O/M) cost are also based on the assumed O/M cost for a typical 1100MW plant. The plant efficiency is based on the plant heat rate multiplied by the number of days the plant is operational and divided by one. The load factor is assumed as 90% since this is a relatively new plant and the plant is assumed to have a 20years lifespan (World Bank, 2013).

The total cost of the CCGT Plant includes the capital cost of the project, operations and maintenance cost and fuel cost. The fuel Cost is the gas volumes required to operate the plant multiplied by the prevailing gas prices or the current Light Crude Oil (LCO) price multiplied by the LCO volumes consumed. The link between the CCGT and the upstream project is embedded in the final price of gas.

4.5.0. Why Gas-to-Power or a Fertilizer Plant in Ghana?

Why gas-to-power development in Ghana? The first reason is the relative strategic importance attached to electricity demand in Ghana and the second is the netback pricing of electricity and other products and projects. The Ministry of Energy final Gas Master Plan (2015) reports identified the power sector as the highest value user of Ghana's gas resources. Hydro-electricity generation potential is exhausted and the increasing generation cost of petroleum fuels has made gas the most reliable fuel for electricity generation and the utilisation of domestic gas in Ghana. Consideration can be given to a fertilizer plant as a strategic investment alternative (Gas Master Plan, 2015).

Table 27: Natural Gas Utilisation Options in Ghana

Utilisation Options	Key Requirements
Power Plant	-Requires reliable and constant supply of gas. -Competitiveness of electricity tariffs would very much depend on how competitive gas prices would be. -Tariffs competitiveness would also require high plant utilisation.
Ammonia Plant	-Economic size of a world-scale ammonia plant would need to be 660,000 tons per year and would require about 60million cubic feet a day (cfd) of gas over at least 20years. A supply level over the Jubilee field's projected gas output at plateau level but possible with other fields (TEN, Greater Jubilee and Sankofa). -Depending on ammonia prices, an ammonia plant would need competitive gas prices of about US$1 to US$2 per MMBTU for the case of a project based in Ghana, which are far below the short-term projected gas prices.
Methanol Plant	-Economic size of a world-scale methanol plant would need to be 1.6million tons per year and would require about 170million cfd of gas over at least 20years. A supply level over the Jubilee fields projected gas output at plateau level unless the Sankofa project which is also dedicated to power plants. -Depending on world methanol prices, a methanol plant would need competitive gas prices of about US$4 to US$5 per MMBTU for the case of a project based in Ghana.
Industries	-Economics of gas to industries would depend on load proximity to gas supply (issues of gas infrastructure-distribution pipelines) and nearby demand (anchors and demand clusters). -Gas prices should be competitive with alternative fuels.

Source: Nexant Report, (2010).

An ammonia/fertilizer plant could be a viable business opportunity in Ghana considering that for a viable fertilizer plant, 60 million cubic feet of gas a day as indicated on Table 27 feedstock is required for a period over 20years. These gas volumes could be assured from any of these gas sources: the Jubilee fields and the TEN fields coming on stream since these are associated gas sources with relatively cheap wellhead prices. The 660,000 tons per year of ammonia produced from the plant would supplement Ghana's increasing fertilizer demand as 239,883metric tons of fertilizer is imported annually

(AfricaFertilizer.org, 2017).

A 30,000MMBtu/day of gas can be spared from either the Jubilee fields, TEN, Sankofa fields or the TEN 50,000MMBtu/day associated gas can be dedicated to the fertilizer plant. A domestic associated gas reserve (with crude oil absorbing all project CAPEX and OPEX cost), dedicated to the fertilizer plant could meet the downstream price requirements of a projected US$1.7/MMBtu to make the plant competitive. This is capable of providing an alternative downstream consumer of gas to prevent the condition of industry monopsony structure in Ghana's nascent gas industry.

4.6.0. Simulation and Sensitivity Analysis

Nersesian (2013) applied the @RISK software developed by Palisade Inc. to model risk in energy projects. The @RISK software is applied to integrated cash flow models' output variables (NPVs) to analyse the uncertainty/risk contained in the model. This presents a slightly different uncertainty/risk modelling output from Herath and Malhotra (1996) and Ibata (2009) integrated cash flow models. The @RISK software incorporates the building of simulation models, which present a variety of scenarios that explicitly incorporate uncertainty/risk with probability distribution. @RISK takes care of the tedious details of uncertainty/risk and allowing careful examination of distributions.

Palisade (2011) states the steps for performing simulation and sensitivity analysis using @RISK software on the integrated cash flow model as:

- The first step is to create an integrated gas industry value chain cash flow Excel model using appropriate Excel formulas to implement the logic that leads from the inputs, the uncertain inputs, and the decision variables to outputs (NPVs).
- Identify the certain and uncertain inputs. Uncertain inputs (e.g. Prices, volumes, cost parameters etc.) are the focus of the model and decide which probability distributions to use for the uncertain inputs and determine the decision variables.
- Designate the output(s) you want @RISK to keep track of and change @RISK setting as necessary, especially the number of iterations and possibly the number of simulations and run the simulation.
- Examine the distributions of the designated outputs with various @RISK tables and charts and perform sensitivity and correlation analysis on the results to see which uncertain inputs have the largest effects on the outputs.

The main advantage of the integrated cash flow model is the ability to perform sensitivity analysis under different business scenarios and negotiating conditions whilst considering the profitability of the projects and their risk using "*what if*" based on a percentage variation from the base case, i.e., the original project NPV. Most importantly, Excel models can facilitate sensitivity analysis where various outputs vary as inputs and/or decision variables are varied in a systematic way.

However, the @RISK software performs sensitivity and correlation analysis together. A 5-100% change on either of the risk factors can be varied to detect its effects on the project NPV. Example, "*what if*" natural gas prices increase by 10%, 20%, 30% or 90%; what happens to the CCGT project NPV? Excel provides a one-way and two-way "*data table*" feature which is more useful and powerful for showing the effects of many different variable settings in a single view (Kasriel and Wood, 2014).

Box 9: Typical Sensitivity Analysis

Influence of varying gas prices, electricity tariffs, processing tariffs, and transmission tariffs on projects NPV. Impact of fiscal policy (royalties) on government and contractor returns. Effects of government take and contractor returns on charging production rate on projects profitability. Effects of changing capital and operating cost on the projects NPVs. Effects of the varying discount rate on the profitability of the projects.

4.7.0. Chapter Summary

The methodology of the study combines the SCP and TCE theories with stakeholder consultations through semi-structured guided interviews and an integrated cash flow model to develop a robust analytical framework to undertake an integrated analysis of the structural, regulatory and governance arrangements and infrastructure investment decisions within the nascent gas industry in Ghana.

CHAPTER FIVE

STRUCTURING THE NASCENT GAS INDUSTRY IN GHANA

5.0. Introduction

Chapter five focuses on the first objective of the study: to evaluate possible gas industry structures in Ghana. The first section of the chapter focuses on the structural challenges identified during the stakeholder consultations. The next sections, however, look at the alternative structures while the final section considers evaluating the different structures. The chapter ends with a conclusion.

During the semi-structured guided interviews with stakeholders, the following questions on industry structure were asked:

a. How would you describe the structure of the gas industry in Ghana?
b. What problems does the current structure pose to your investment?
c. Should the industry be restructured?
d. What possible industry structure do you recommend?

5.1.0. The Current Structure of the Gas Industry in Ghana

Stakeholders identified the current structure of the gas industry in Ghana as state-controlled or a state monopoly of vertically integrated structure. This current structure is government-led as espoused by the Ministry of Energy, GNPC and GNGC and is similar to the VIM/SBM. The interviewee in the Ministry of Energy edged for VIM/SBM at the initial and infantile stages of development [Min-Energy]. However, other interviewees [Midstream-EC and IOC-ENI] argued for a rather competitive structure.

In particular, one of these interviewees noted that the current structure of the gas industry in Ghana is "*confusing"* and "*in a state of a mess*" [IOC-ENI]. The structure of the gas industry, which is largely described, as a competitive model by current laws are not being implemented though the Energy Commission Act 1997 (Act 541) states their mandate as:

> '*Promoting competition in the supply, marketing and sale of petroleum products*[26]' [Midstream-EC].

In this model, one interviewee [Midstream-EC] emphasised that upstream production/supply of petroleum products including gas will be open to competition, and the transmission of gas will operate on open access basis as indicated on the Energy Commission Natural Gas Access Code:

> '*Promote the development of a competitive gas market by establishing uniform principles for owners and users of gas pipelines to allow transparent and non-discriminatory access to the gas transmission system*' [Midstream-EC].

The existing gas industry structure in Ghana identified in the stakeholder consultation (VIM/SBM) is different from what is stated in the above Energy Commission Act (541) and the Energy Commission Natural Gas Access Code (a Competitive structure). These contrasting structures present a challenge to the nascent gas industry in Ghana. The question arising from this, then, is 'how can a suitable gas industry structure be developed for the nascent gas industry in Ghana?'

5.1.1. Challenges of the Current Gas Industry Structure in Ghana

The stakeholder consultations and the NVivo analysis identified five

[26] Petroleum products are liquid or gaseous fuel and lubricants derived from crude oil (Energy Commission ACT 541

major challenges in the gas industry in Ghana as indicated on Table 28.

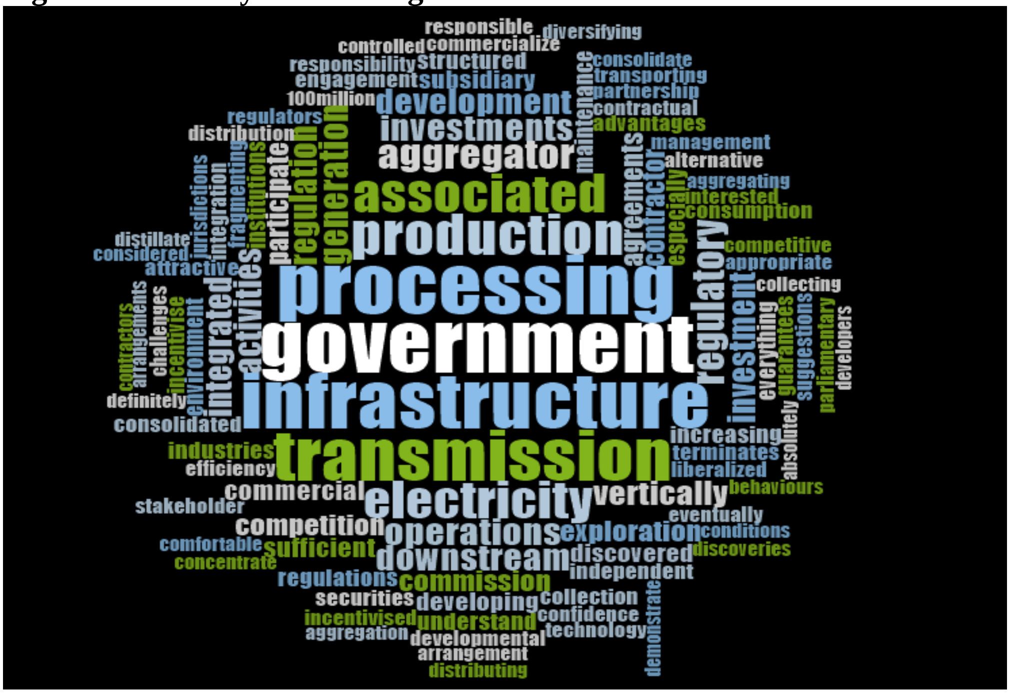
Table 28: Challenges Identified from Stakeholder Consultations

Stakeholder Identified Challenges	**Segment**
Lack of appropriate industry structure	Upstream, midstream and downstream
Lack of appropriate regulations	Midstream and downstream
Lack of clarity in roles and responsibilities	Midstream and downstream
Institutional conflicts	Upstream and Midstream
Lack of clarity in contractual obligations and gas pricing	Downstream

Source: Data from Interviews.

In the NVivo analysis Node: structuring the gas industry in Ghana, the two most frequent words featuring are '*Governmen*t' and '*Infrastructure*'. Government, through GNPC, plays the dominant role in the current gas industry, and infrastructure presents the most important concern to industry players. Other frequently used words include '*aggregator*', '*regulatory*', '*prices*', '*investmen*t', '*electricity*', '*vertically*' and '*competition*' as indicated on Figure 8. This trend of word frequency establishes that government ownership of infrastructure and government-leading role in the gas industry are the main themes of the nascent gas industry in Ghana.

Figure 8: Industry Structuring Word Cloud



Source: NVivo QSR 11.

5.2.0. Alternative Natural Gas Industry Structural Arrangements

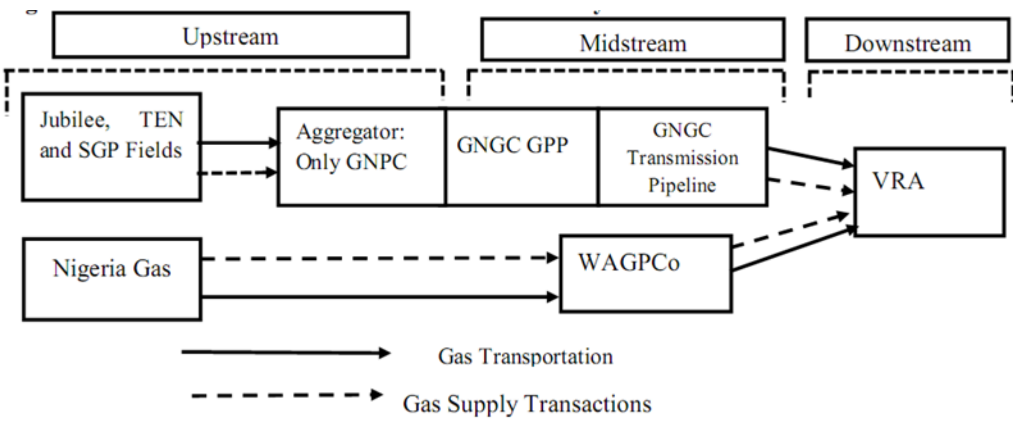
TCE assumptions of asset specificity, uncertainties and frequency of transactions (Spanjer, 2009; Ghosh and Kathruria, 2015) provide the theoretical analytical framework for evaluating the various structural models of the gas industry in Ghana. A particular structure is selected based on the efficiency of its transactions in the timeframe instead of market power strengthening (Lafontaine and Slade, 2010; Mahoney et al., 2007).

GNPC (upstream) aggregates associated gas upstream to be delivered to Ghana National Gas Company (GNGC) (midstream) processing plant for processing and transmission through the GNGC pipeline to Volta River Authority (VRA) as the only downstream consumer. GNGC operates as a subsidiary of GNPC. GNPC is the off-taker for the Sankofa Gas Project and has the only license for the importation of Liquefied Natural Gas (LNG) into Ghana. GNPC is regarded as the national gas aggregator.

The domestic production/supply of gas are under the remit of GNPC as the aggregator and as the LNG importer. GNPCs domestic gas supplies are sold to a single downstream consumer, which is VRA. A fixed structure: GNPC-GNGC-VRA is created as indicated on Figure 9 to handle domestically produced gas in Ghana, a system described as a state monopoly and vertically integrated with a single buyer.

On the other hand, the West African Gas Pipeline Company (WAGPCo) (midstream) has been in the business of transmitting gas from Nigeria to VRA (downstream) in Ghana. Nigeria Gas (N-Gas) is the gas shipper, which arranges upstream gas from Nigeria to be delivered to downstream consumers in Benin, Togo and Ghana. In Ghana, VRA is the buyer of Nigerian Gas (N-Gas) gas. On the WAGP, N-Gas is the only owner of transported gas. Natural gas from Nigeria presents the structure: N-Gas-WAGP-VRA, which is described as a firm structure. Wholesale supply of gas into Ghana presents two firms structures: GNPC and N-Gas (in the upstream) through two main pipelines: GNGC pipeline and WAGP (in the midstream) to one major consumer, VRA (downstream).

Figure 9: Current Structure of the Natural Gas Industry in Ghana



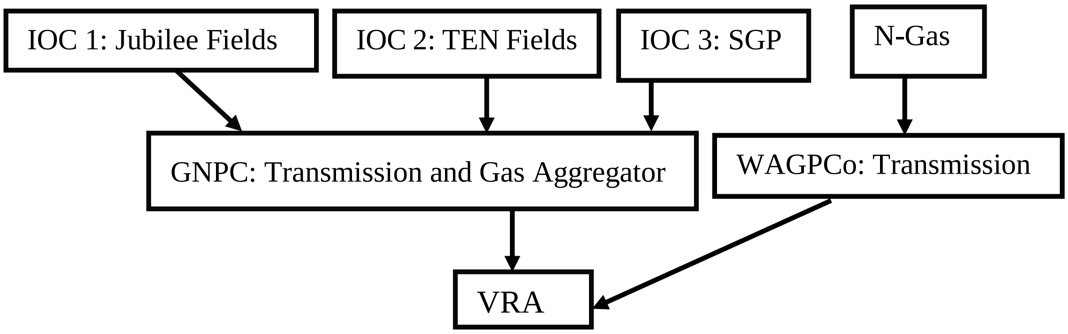
Source: Adapted from Weijermars (2010).

Figure 9 captures the current structure of the gas industry in Ghana. There are two pipelines in this early phase development: West African Gas Pipeline and the Ghana Gas Company pipeline. Both transmission pipelines have open access regimes even though they have not been effectively operational [Midstream-EC and Midstream-WAGPCo].

5.2.1. The Single Buyer Model in the Natural Gas Industry in Ghana

It is not very clear whether the current gas industry structure in Ghana is VIM or SBM. For domestically produced gas, there is a firm structure: GNPC-GNGC-VRA structure, similar to SBM as upstream gas production is open to competition. GNPC (the single buyer) procures gas through long-term production contracts from upstream producers (IOCs) after which the gas is delivered through a regulated pipeline to a single downstream consumer, VRA. On the other hand, N-Gas procures gas from upstream producers in Nigeria in long-term contracts to be delivered through the regulated WAGP to VRA in Ghana as indicated on Figure 10.

Figure 10: Schematic of SBM in Ghana



Source: Adapted from Bhattacharya (2011).

Domestically produced gas from three International Oil Companies (IOCs) (Jubilee fields, TEN and SGP) are aggregated, processed and transmitted by GNPC delivered to VRA. With this, GNPC serves as the single buyer upstream while VRA serves as the single buyer downstream. N-Gas, on the other hand, procures gas from several IOCs in Nigeria and delivers to VRA. Though two parallel structures, VRA serves as the single downstream gas buyer in Ghana in both cases.

Upstream gas production/supply however, is open to competition. The GNGC transmission pipeline and WAGP are regulated monopolies by Energy Commission (EC) and the WAGP Authority in Nigeria respectively. The Public Utilities and Regulatory Commission (PURC) and the WAGP Authority regulate natural gas tariffs.

In SBM, transmission pipelines and downstream consumers must work completely independently and tariffs need to be set by an independent regulator (Celik, 2003). GNPC controls the GNGC transmission pipeline even though WAGP is independent of N-Gas. Although production/supply is competitive, consumption is a monopsony with only VRA while gas prices and transmission tariffs are set by PURC. Thus, the current gas industry structure in Ghana can best be described as SBM than VIM.

Why SBM in Ghana's nascent gas industry?

SBM is considered adequate in the early stages of the gas industry (Juris, 1998; Riordan, 2008; De Mello Sant Ana et al., 2009; Bresnahan and Levin, 2012, Williamson, 2010) where a single purchasing agency is introduced at the wholesale level to perform transmission and wholesale gas supply functions. Accordingly, GNPC is selected as the upstream aggregator and wholesale agency to coordinate domestic gas supply and demand in Ghana.

The SBM is a dedicated asset framework designed by the Ghana Government to monetise domestic gas resources, which were previously flared. This arrangement led by GNPC is an integration policy agenda designed by the Ministry of Energy. These informal institutions form the basic view of the market where the gas industry policy is determined. The Ministry of Energy's policy for the gas industry, for now, is to operate an integrated system (SBM).

In the interviews with GNPC, GNGC and the Ministry of Energy, several reasons were given for establishing an early stage and short-term SBM for domestically produced gas in Ghana [Upstream-GNPC, Midstream-GNGC; Min-Energy]. As part of the arrangements, GNPC is to act as the upstream gas aggregator to deliver associated gas to the GNGC midstream infrastructure, the GPP and methane gas, through the GNGC transmission pipeline to VRA. GNPC is to act in a similar capacity to deliver regasified LNG to dedicated thermal plants in the Tema industrial enclave.

In the interviews, it was explained that GNPC is the state partner in all upstream petroleum agreements and as per the upstream petroleum regulations, it is mandated to act as the aggregator of all upstream produced associated gas with the vision of facilitating midstream and downstream commercialisation activities and curbing flaring [Upstream-GNPC; Min-Energy]. This is captured in the statement:

> '*There will be only one supplier of gas essentially and that is GNPC*' [Min-Energy].

The structure is to have a single purchaser of upstream gas/aggregator from the Jubilee Fields, TEN and SGP, making the supply of upstream gas a monopoly [Midstream-EC].

The SBM is regarded as an economically and technically efficient structure to monetise previously flared gas in Ghana. Kwoka (2001) added that for cost-effective, economic and technically efficient reasons, it is better to operate the SBM. At this infantile stage, the most important need was to avoid gas flaring and to monetise the gas for power generation. The interviewee at Ministry of Energy succinctly stated that GNPC being the national gas aggregator is to enable logistical transmition of gas in the country through dedicated asset [Min-Energy].

SBM is seen as the most efficient response to reduce commercial uncertainty, mitigate against contractual incompleteness (Bresnahan and Levin, 2012; Williamson, 2010) and provide appropriate risk guarantees for gas project bankability. For instance, GNPC had to provide financial guarantees in the form of bankable balance sheets and letters of credit as well as serve as a credible off-taker to upstream gas projects. GNPC seems to be the only most credible off-taker in the energy sector in Ghana.

5.2.2. TCE and SBM in Ghana's Nascent Gas Industry

TCE and the stakeholder consultation influencing the SBM policy are based on the TCE assumptions of asset specificity, uncertainty and transactions frequency (Ruester and Neumann, 2009). Asset specificity in capital, physical and human expertise is the strongest determinant for the SBM policy (Ruester and Neumann, 2009; Neumann and von Hirschhausen, 2006). During the interview with GNPC it was stated that, GNPC is involved in all upstream petroleum contracts with IOCs with carried and participation interest in projects. GNPC has the technical and financial expertise to lead in the development and monetisation of gas resources in Ghana [Upstream-GNPC].

Initially, IOC's were not interested in developing or investing in midstream infrastructures such as the GPP and a transmission pipeline; consequently, associated gas was flared in crude oil production to the detriment of downstream power plants' requirements. Subsequently, the Government of Ghana had to secure a Chinese Development Bank loan of US$3billion and make GNPC the technical and economic advisor to the Ghana Gas Company Project[27]. US$1billion was, thus, invested in the development of a midstream

[27] Ghana Gas Company Projects – Included constructing a 150,000MMBtu/day gas processing plant, 60km offshore pipeline and a 114km onshore pipeline

gas infrastructure to provide an alternative fuel to thermal plants and ensure fuel security by relying on domestically produced gas, especially when gas supplies from Nigeria were inadequate and unreliable and LCO considered expensive.

The Sankofa Gas Project is another example of the dominant role of GNPC. GNPC, on behalf of the Ghana Government, provided financial risk guarantees and serves as the off-taker for the commercialisation of SGP. The SGP partners[28] required a credible upstream off-taker to reach final financial closure and GNPC was elected to play that role because of their existing financial credibility. GNPC, thus, was made a partner to the SGP agreements. These gas contracts are long-term and require credible off-takers to provide financial support (Razavi, 2007).

Saussier (2000) noted these assets (the GPP, FSRU and the transmission pipelines) are site-specific with their investments considered irreversible. These are capital intensive infrastructure investments (Weijarmars, 2010) and are project specific, requiring quasi-rent negotiations[29] which leave small room for competition and, according to Neumann and von Hirschhausen (2006), lead to the SBM or vertical integration (Williamson, 2010).

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[28] Sankofa Gas Project commercialisation partners: World Bank Guarantees, IFC leading and MIGA political risk insurance are to support the Government of Ghana and private parties (ENI, Vitol and GNPC).

[29] Quasi-rent negotiation is where the suppliers' returns are guaranteed through government protection by restricting entry and this according to Williamson (2010) allows vertical integration. And the more difficult it is to find substitute performance or to redeploy investments to alternative uses, the larger the appropriable quasi-rent and the greater the risk that transactional surpluses will be dissipated as the parties engage in hold-ups or other forms of opportunistic behaviour attempting to influence the terms of trade to their favour (Crooker and Masten, 1996).

Each of the investments from the IOCs and Ghana Government is considered capital intensive, not having an alternative use except for the benefit of the gas industry and creates hold-up problems (von Hirschhausen, 2015). The asset specificity and dedicated nature of existing infrastructure limit other private sector players from participating in both midstream and downstream segments due to the long-term contracts to which investments are committed.

Long-term contracts are seen as a tool to avoid the risk of opportunistic behaviour in transactions (von Hirschhasen et al., 2015). Most of these energy-intensive infrastructure investments display hold-up and lock-in problems, which are solved through long-term take-or-pay contracts between the investors and buyers. These are considered long-term risk allocation mechanisms, used as collaterals in project finance where the project serves as a recourse to banks, and are designed to protect the interest of the investors. They often occur where the investor has to undertake huge debt and capital commitment in an uncertain environment (Energypress, 2014).

When these infrastructures are finally built under long-term take-or-pay contracts, they seem to restrict access by third parties since these are dedicated assets under specific contractual agreements. These are often used as market foreclosure or anticompetitive tools (Energypress, 2014). GNPC assumed the role of a guaranteed buyer in most of the take-or-pay contracts such as the SGP, the FSRU infrastructure project and the "GNGC infrastructure project" [Min-Energy; Upstream-GNPC]. With a higher degree of asset specificity in the uncertain gas industry in Ghana, SBM is considered appropriate in order to protect infrastructure investors [Upstream-GNPC].

However, these long-term contracts, which resorted to the current SBM, are seen as tools to secure monopolistic rents (von Hirschhausen, 2015). There are other downstream consumers aside VRA who are willing to pay for gas and need a secured and adequate supply of natural gas. Furthermore, pipelines seem to express less asset specificity if they are allowed to operate under open access regimes (Mulherin, 1986).

In the midstream, there are two transmission pipelines whose capacities can be increased and which could be interconnected through additional compressors and a backflow/reverse flow technology. The SBM is less feasible when there are alternative pipeline systems (Mulherin, 1986). These will reduce the asset specificity of pipelines and enable asset re-deployability, especially in extra capacity usage.

Easing the completion of gas purchase contracts and avoidance of contractual renegotiations is considered an important reason for maintaining the SBM (Saussier, 2000). One interviewee explained that historically, the electricity industry in Ghana has not been able to pay for the gas it has been consuming from Nigeria [Upstream-GNPC]. For new natural gas purchase contracts and as a risk mitigating measure, IOCs requested for securities and risk guarantees from the main downstream gas consumer VRA. However, VRA's balance sheets were not bankable (see Table 13) because the wholesale buyer of electricity, Electricity Company of Ghana (ECG) had not paid for over 60% of power purchases (World Bank, 2015).

This is a very critical issue in developing countries since the end-users are unable to pay for the natural gas they consume. It is, also, among the reasons why it is difficult to attract infrastructure investments into the other segments of the gas industry in such countries. New gas purchase agreements with VRA are risky; hence, the need for alternative off-takers for upstream gas. With the Bankability of the Sankofa Gas Project, one interviewee explained that the Government of Ghana had to rely on GNPC as the only credible off-taker:

> *'….having GNPC step in with oil reserves securities will reduce the requirements for some of these projects and it is easier for some of these contracts to be signed. GNPC don't have to put up cash upfront for securitisation because the future revenues from oil can provide the necessary security for these agreements'* [Downstream-EC].

GNPC assumed a single buyer role as a credible off-taker to these gas contractual agreements. However, GNPC will still have to deal with the non-credibility of VRA whilst gas could be arranged to be sold directly to various IPPs as end-users to revert the hold-up risk of a single downstream buyer. This arrangement exposes GNPC to the risk of VRA and ECG non-payments for the purchase of electricity since the gas industry depends on the electricity industry's payment for gas purchases. GNPC is held-up and locked in VRA and ECG's risk of non-payments, which will affect the gas industry value chain.

The main challenge of the current SBM is how to avert the existing hold-up and lock-in problems between GNPC and VRA in gas purchases and how ECG can efficiently payback fully electricity purchases from VRA. If this is resolved, VRA can finance their fuel purchases and be able to payback the gas value chain including GNPC for subsequent payments to the IOCs. Alternative gas consumers or gas sales to different IPPs will reduce the over-reliance on VRA as the only single downstream buyer. Direct gas sales to IPPs instead of VRA will reduce the hold-up risk and the burden on VRA as the single gas buyer and will diversify downstream gas buyers whilst solving ECG inefficiency challenges.

Minimises Uncertainty: SBM mitigates investment risks in the form of “hold-up” and lock-in problems (Dahl and Matson, 1998). Lack of willingness and inability to pay was identified by one interviewee as a major concern for the gas industry in Ghana, at this infantile stage [Upstream-GNPC].

Investment in a natural gas asset is immobile, has low salvage value and is highly asset specific, leading to the possibility of opportunistic behaviour in contract non-compliance and causing uncertainties to initial investors (Dahl and Matson, 1998). The natural gas markets can develop when contracts between producers, suppliers and buyers are credible, complete and have low risks of opportunism (Ghosh and Kathuria, 2015). Upstream gas producers require credible purchasers of gas to sign long-term contracts before production can be assured or their revenue streams, secured. GNPC serves as a risk-free partner in upstream gas production transactions in Ghana.

Providing financial guarantees and securitisation is the most enduring reason for the SBM policy, especially when World Bank was to provide the partial political risk and sovereign risk guarantees for the development of SGP.

GNPC proved to be the most credible Government institution in the energy value chain to serve as off-takers [Upstream-GNPC].

Although GNPC could solve part of the problem in the entire energy industry by being a credible upstream off-taker for gas projects, it cannot solve the inefficiencies embedded in the final delivery of gas to VRA and ECG. GNPC could, also, not solve the accumulated debt and repayment problems of VRA and ECG [Min-Energy]. There exist uncertainties in debt accumulations due to the inability of the main downstream gas consumer (VRA) to fully pay for the consumed gas owing to inefficiencies of ECG to adequately collect electricity tariffs from consumers (World Bank, 2015).

In the end, GNPC's financial position will be overburdened with having to serve as a guarantor to several gas projects and dealing with VRA and ECG, which have low financial credibility. Also, GNPC's financial position maybe affected and weakened by low prices in the global crude oil market, making its ability to play the role of a risk-free off-taker of gas diminish.

Frequency of transactions: a recurrent frequency of transaction is a justification for considering alternative structures (Willaimson, 2010). GNPC had to provide financial guarantees for the SGP and serve as an off-taker for other gas projects such as the Jubilee field, TEN project and FSRU [Upstream-GNPC]. GNPC is elected to be the only buyer of upstream gas estimated at 350,000MMBtu/d; these are recurrent transactions expected daily.

The viability of GNGC Gas Processing Plant is directly dependent on upstream production of associated gas. Therefore, with GNPC as the only gas aggregator, GNGC GPP is assured of associated gas supplies to remain viable and be able to pay for the outstanding Chinese Development Bank US$1billion infrastructure loan facility.

There is, however, a problem when natural gas is sent to VRA downstream for power generation as VRA has proven to be non-credible off-taker indebted to major gas suppliers. On recurrent (daily) basis, GNPC will be delivering an estimated 350,000MMBtu of gas to VRA, which implies that GNPC is exposed to the uncertainty of VRA's existing non-payment risk.

VRA uses these gas volumes to generate electricity and frequently supplies thermal power to ECG on daily basis. Yet, ECG, as the bulk buyer of electricity, is unable to collect economic electricity tariffs and efficiently mobilise tariffs to pay VRA. The existing SBM in the power sector, as well, does not provide alternative large-scale buyers of VRA's electricity, and this locks-in GNPC to the indebtedness of VRA and ECG.

ECG has a natural monopoly of downstream electricity distribution in Ghana but is considered inefficient as it records 23% of technical and commercial power losses, which result in a considerable amount of revenue loss annually (World Bank, 2018). Kao et al., (2014) noted that the introduction of competition in the downstream distribution of electricity would enhance efficiency in electricity tariff mobilisation.

The SBM poses two main challenges to the nascent gas industry: the hold-up problems in the GNPC-VRA-ECG link and cost recovery issues. This affects the gas supply chain viability and makes investment uncertain. The SBM tries to address these challenges by artificially hiding issues within the government-owned entities, but this does not generate investor confidence. The SBM will not diminish the ex-post investment risk in the gas industry due to the hold-up and lock-in problems from VRA and ECG. It will require the consideration of selling natural gas to alternative consumers to avert VRA non-payment problems and inject efficiency into electricity transmission and distribution and into ECG tariff collection.

The SBM further discourages investors from entering the gas industry since there are higher investment uncertainties/risks: hold-up and lock-in problems between the gas aggregator, downstream consumer and electricity tariff mobilisers. Potential investors are not attracted to the industry because they expect the gas industry to work efficiently and be able to pay for itself through viable processes [IOC-ENI-Ghana].

Can these challenges be solved under the SBM? There are attempts by the Ministry of Energy to recapitalise VRA's thermal power generation to be listed on the Ghana Stock Exchange [Min-Energy]. This will inject liquidity and efficiency into their operations. In addition, there are attempts to privatise the management of ECG operations through a management concession program under the Millennium Challenge Account Compact II agreement.

However, these are not guaranteed actions to reduce the higher uncertainties to the nascent gas industry in Ghana. The structural solution is to diversify downstream gas consumption and divert gas purchases to alternative large-scale users either in the power sector or to other consumers. The new structural model should be able to provide solutions to SBM.

5.3.0. Multiple Buyer Model in the Gas Industry in Ghana

Juris (1998) noted that in SBM, the utility companies often lack the flexibility required in a dynamic market environment. In addition, regulation is often insufficient to induce efficient operations. Governments seek to look for alternative structural models with potential for higher efficiency and cost savings. Lu et al. (2016) further noted that to ensure gas supply security is to diversify supply sources. MBM assures greater flexibility and more efficient functioning of the gas market (Radezki, 1999).

The first consideration for MBM is to avert the hold-up and lock-in problems inherent in SBM. In addition, it allows consumers and producers/suppliers direct transaction access. MBM allows the introduction of multiple buyers of natural gas at the wholesale level. Contrary to SBM, interviewees at ENI-Ghana and the Energy Commission argued for a liberalised policy and unbundling the activities of GNPC as the single upstream gas aggregator and infrastructure owner [IOC-ENI; Midstream-EC]. Their argument is that there should rather be multiple buyers of upstream gas. The arguments of the ENI-Ghana and the Energy Commission for a liberalised industry structure agrees with Joskow's (2000) assertion that in the past 25years, the energy sector, including the gas industry, has witnessed market liberalisation [IOC-ENI; Midstream-EC].

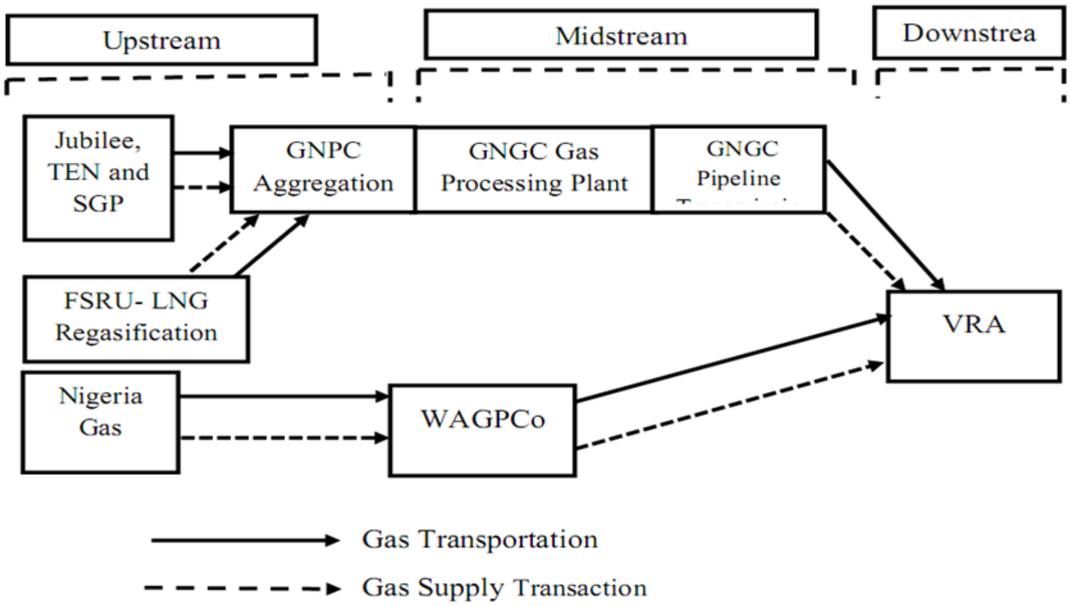
Joskow (2000) noted that there are potential benefits of market forces replacing inefficient regulated monopolies. As well, there is a cost to vertical separation with its associated contractual hazards when they are being disintegrated. This raises issues and the advocates [Midstream-EC; IOC-ENI-Ghana] argued that the MBM should be promoted even at the infantile stage of the nascent gas industry in Ghana.

Since the monetisation of the Jubilee Fields' associated gas through the development of midstream infrastructure, there have been numerous modifications to the gas industry structure as several other offshore fields were discovered. The Jubilee Field was expanded to include the Greater Jubilee and the TEN fields. The Sankofa Gas Project (SGP) was also introduced to produce significant volumes of non-associated gas. Furthermore, there are investments into an FSRU to receive LNG.

The supply of domestically produced natural gas comes from multiple sources, and this has changed the initial structure of the gas industry. From 2018, there will be several IOCs producing gas from multiple sources (World Bank, 2015). Figure 11 indicates the sources of domestically produced gas from Jubilee and Greater Jubilee, TEN, Sankofa Gas Project (SGP), the construction of FSRU to regasify LNG and WAGP supplies.

Some interviewees noted that the existing SBM structures: GNPC-GNGC-VRA and N-Gas-WAGP-VRA need to be altered to allow IOCs direct access to downstream consumers (IPPs) and vice versa [IOC-ENI; Midstream-EC]. This will avert the dependence on a single upstream buyer and the uncertainties and hold-up problems of a single downstream buyer (VRA and ECG). In view of the inefficiencies of the current structure, a transitional structure such as the MBM is considered for the nascent gas industry in Ghana (Bhattacharyya, 2011).

Figure 11: Introduction of Competition in Gas Production/Supply



Source: Adapted from Juris (1998).

MBM is considered as a transitional model from the existing SBM to competitive structures because the risk of moving directly to spot markets may outweigh the benefits (Bhattacharyya, 2011). The MBM contains some of the features of VIM, SBM or wholesale competitive models. Two of such models for consideration are the Multi-buyer Multi-seller model without retail competition (MBM: A) and the Multi-buyer Multi-seller model with limited retail competition (MBM: B).

5.3.1. Multiple Buyer Multiple Seller Model without Retailing (MBM A)

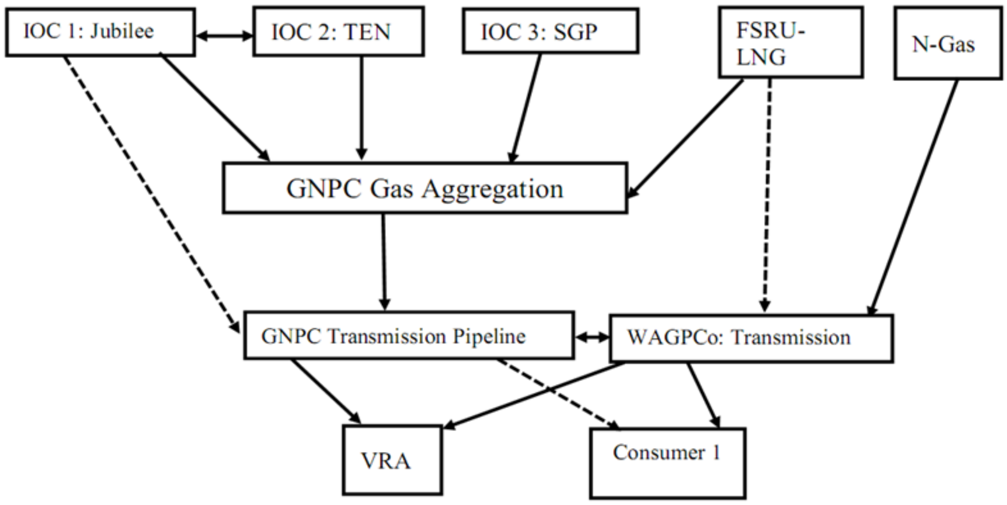
A new segment will allow competitive trading of natural gas where upstream producers/suppliers can sell gas competitively without any restrictions. This is possible when the gas producers/suppliers discover extra gas supply sources than the fixed contractual agreements with the single buyer which is GNPC for both domestic gas and imported LNG. This extra capacity may be initially small but will increase over time. The producers/suppliers will compete to sell these extra volumes to distributors using bilateral contracts for physical delivery.

MBM: A introduces a limited amount of retail competition by allowing large-scale gas consumers to purchase gas directly from producers/suppliers through bilateral contracts. Consumers will have the choice of gas supply either from supplying companies or directly from producers. These large-scale consumers will be selected based on selection criteria such as consumption capacity, access to transmission pipelines, size and their ability and willingness to pay economic prices. The initial SBM however, will remain unchanged.

On Figure 12, the thick lines are the current transaction links while the dotted lines indicate future/potential transactions. The existing contractual agreements for the Jubilee, TEN and SGP is maintained under the SBM or renegotiated with GNPC as the single buyer, which is limited to the contractual volumes, prices and other terms. Additional discoveries or increasing volumes would be competitively traded through negotiated bilateral contracts depicted by the dotted links. The GNGC transmission pipeline will be unbundled from GNPC to operate with WAGP on open access basis. The two pipelines are to operate on a reverse/backflow technology to allow the efficient exchange of gas between the two demand enclaves in Ghana (Tema and Takoradi).

The upcoming FSRU-LNG can provide much more gas supply flexibility for wholesale traders to facilitate a quicker transition into competitive markets, especially if downstream consumption is open to competition. Wholesale suppliers and consumers can now directly arrange for their own LNG and use the FSRU as a tolling facility, given a guaranteed access to the transmission pipelines to deepen competition in gas trading.

Figure 12: MBM: A in Ghana's Gas Industry



Source: Adapted from Bhattacharyya (2011).

In addition, the MBM: A will promote competition of upstream gas production and diversify natural gas supply to the aggregator (GNPC). The extra gas capacities, as well, can be sold to alternative consumers on negotiated contractual arrangements or on the spot markets. This will lead to the possible creation of a spot market or negotiated contractual arrangements. In the negotiated contracts, bilateral sales to large-scale consumers will give gas suppliers more flexibility with a limited form of competition. In the case of a spot market, wholesale market competition will be deepened as gas consumers and suppliers are given choices to decide where to buy, sell and at what price.

However, the MBM: A restricts small-scale consumers' participation in the industry and gives prominence to only large-scale consumers through a consumer selection criterion. This limits competition and restricts gas market penetration, especially in a nascent gas industry such as Ghana where gas usage penetration should be encouraged in small-scale industries for a wider coverage.

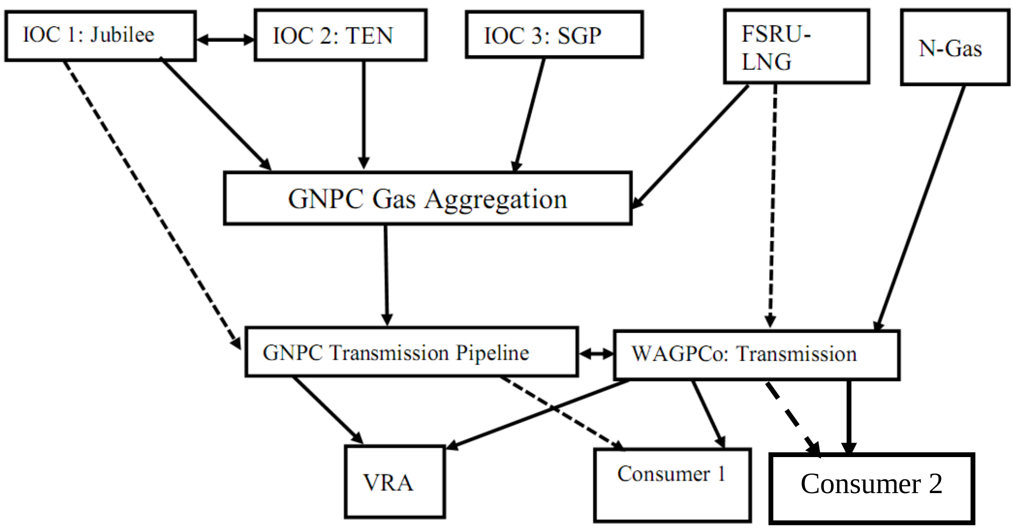
5.3.2. Multiple-Buyer Multiple Seller Model with Retailing (MBM: B)

The MBM: A allows limited amounts of retail competition by allowing only larger consumers to purchase/enter into long-term Gas Purchase Agreements so that they can directly receive gas from upstream producers/suppliers. MBM: B, on the other hand, will allow gas retailing and direct gas transactions with small gas consumers such as small-scale industries and industrial consumers as indicated on Figure 13. Small consumers can now directly trade in gas with producers/suppliers through bilateral contracts or spot markets. The criteria for entry will be their ability and willingness to pay economic tariffs.

Additional improvements on MBM: A will be to allow existing upstream gas producers or new gas producers/suppliers direct access to the two existing transmission pipelines to deliver their gas to consumers directly without the single buyer agency (GNPC) and the inclusion of several other small-scale consumers. However, a balancing market will be required to manage the day-to-day operations of the new structure, and this will increase the complexity of the market. Bilateral gas contracts can be signed between upstream gas producers (IOCs)/suppliers and downstream gas consumers. MBM: B will require distributing lines to deliver gas to these small consumers.

The SBM indicates the risk of hold-up and locked-in to VRA and ECG inefficiencies. If producers/suppliers can avert the hold-up role of GNPC as the only upstream gas aggregator ex ante to all domestically produced gas and can sell extra gas to other third parties (gas consumers or gas trading partners) on negotiated bilateral contracts, they can make alternative arrangements with other downstream consumers. This will reduce their current risk exposure to VRA and ECG and diversify downstream gas consumption in Ghana.

Figure 13: MBM B in Ghana's Natural Gas Industry



Source: Adapted from Bhattacharyya (2011).

Will MBM ensure the viability of the nascent gas industry in Ghana? Are there credible downstream gas buyers in Ghana? The choice of the downstream consumers will be dependent on their ability to pay for the gas.

Large-scale gas consumers/buyers are thermal power generators, who require substantial volumes of gas on continues basis for electricity generation. Whether large-scale gas consumers in Ghana can support upstream gas investment projects raises a critical challenge since most of these thermal plants are small-scale plants ranging from 100 to 250MW.

Can the alternative large-scale and small-scale consumers be able to pay for the prices of gas offered directly by the upstream gas producers/suppliers? This will depend on the viability of thermal plants, the netback value of the other users and the spark spread[30] between gas and electricity prices as well as competitive fuel prices (LCO and distillate fuel). Interviews with IPPs confirmed that, as IPPs and large/small scale consumers, they are interested in reliable, available and secure fuel supply [TICO-IPP, TAPCO-IPP; SAPP-IPP]. Moreover, they prefer natural gas to LCO for economic, technical and environmental reasons and are willing to pay economic prices for natural gas.

These IPPs will therefore, have to avert selling their electricity to VRA and ECG and rather consider commercial and industrial power consumers who can readily pay for their power at economic rates. Not until VRA and ECG are able to sustain and pay for the fuel they consume, the gas sector should avert them. By this, instead of one entity defaulting, the issue is distributed. In

[30] Spark spread is the profitability of a thermal plant which buys natural gas to produce electricity: this is the difference between the cost of electricity generation using natural gas and price of electricity sold from the thermal plant.

addition, depending on the volume of gas bought, small-scale consumers will be able to negotiate prices and are likely to face high-cost gas that may affect their viability. GNPC, on the other hand, via SBM is able to cross-subsidise gas.

What are the transaction cost implications of MBM to the gas industry in Ghana? Market Power Control by ENI-Ghana: Allowing upstream operators' access to downstream consumers will also mean alternative integrated activities may emerge from other IOCs. For instance, interviewees from ENI-Ghana and GNPC hinted that ENI-Ghana has the financial and technical capacity to develop an integrated gas value chain similar to that in Tanzania where they produce upstream, invest in midstream transmission pipelines and feed gas into their own thermal plants downstream to generate and sell electricity into the national grid [IOC-ENI-Ghana; Upstream-GNPC].

This implies that a private entity will have to compete with the existing government SBM structure (GNPC-GNGC-VRA structure) as an alternative vertically integrated entity. However, one interviewee confirmed that because of government interest, ENI will not be allowed to pursue such models [Upstream-GNPC]; these sentiments are referred to as government opportunism (Williamson, 2010).

Cost of disintegration and contractual hazards: Over the years, VRA increasingly became indebted to the various IPPs and was unable to secure reliable and economically efficient fuels for them. A major complaint from the IPPs during the interviews was that their fuel supply choices are limited to VRA even though they prefer natural gas to LCO [TICO-IPP; TAPCO-IPP; SAPP-

IPP]. Existing VRA and IPP power purchase contracts can be maintained/renegotiated with new contracts that require VRA to serve as an off-taker for only electricity purchases and not both.

The renegotiation of these contracts can, nevertheless, be hazardous to both parties. This will send a wrong signal to other potential IPP investors of unstable regulatory systems in the Ghanaian power/gas sector, and this may affect the potential of attracting other IPPs requiring the design of new industry structures that may align existing IPPs and take thermal power generation control from VRA.

The MBM will introduce the challenge of how to coordinate gas transmission pipelines and supplies investments (Joskow, 2000). Natural gas produced will need to be transmitted to consumers so a gas source is connected to consumers through transmission pipelines. If there are increasing gas suppliers, there must be efforts to allow access to pipelines and increase investments in transmission pipelines and downstream infrastructures.

With the SBM, the single buyer company knows the gas quantities, their transmission capacity and the capacities of their downstream consumers. However, with MBM, production quantities, transmission pipelines and downstream demand requirements must be efficiently coordinated in that supply is matched to demand and vice versa.

Transmission investments can be lumpy, require longer planning, permission and construction times (Joskow, 2000). Natural gas supplies require exploration and production activities, which involve huge sunk cost and investments. The trade-off between the location of new natural gas supply sources and investments in new transmission pipelines is complicated by the interdependencies of demand and supply. Joskow (2000) noted that the SBM could easily coordinate gas supplies and transmission investments and internalise potential network externalities as compared to MBM. The successful implementation of an MBM requires “overinvestments” in transmission, downstream gas consumption infrastructure and other common infrastructure capacities compared to SBM (Joskow, 2000).

MBM allows multiple bilateral contracts. If each supplier enters into different negotiated price contracts, what are the transaction cost implications? Negotiated contract pricing is the mechanism by which a competitive governance structure strives (Sutherland, 1992). This will promote relationship specific and transaction-specific investments between these contracting parties (Williamson, 2007) requiring long-term contracts to ensure positive returns on their investments. This long-term contract mitigates against opportunistic behaviour that gives the parties ability to renegotiate the contracts.

Natural gas prices will become competitive and efficiently priced due to the activities of market forces. Long-term fixed non-negotiated prices in natural gas contracts are economically inefficient and untenable in a competitive governance structure (Sutherland, 1992). With negotiated prices, asset specificity will reduce since this introduces multiple gas owners, which will mean that upstream gas suppliers will now have the option to deal with alternative off-takers.

The implication of asset specificity is that a long-term contract may have lower transaction cost than a short-term contract that is frequently renegotiated (Sutherland, 1992). Upstream gas producers in Ghana may have lower transaction costs with longer-term contracts with a single buyer than with several customers with different negotiated prices.

Negotiated price contracts with different shippers and consumers will then require pipelines to operate as common carriers of upstream gas (Sutherland, 1992). This means that upstream producers, shippers and downstream consumers must all have equal access to the transmission pipelines and other common infrastructures such as the GPP, FSRUs and storage facilities on negotiated short-term and long-term basis and prices.

The key issue in transiting to MBM will be to unbundle the transmission pipeline system and invest in the transmission network. The transmission network will have to operate under an effective open access and on non-discriminatory basis serving all the parties and not exclusive to the de facto aggregator or asset owners or excluded few. The MBM will, thus, introduce flexibility in dealing with suppliers and buyers of natural gas.

Consequently, the MBM will have several implications for the nascent gas industry in Ghana. The first concern borders on whether the downstream consumers are credible enough to commit to buying sufficient quantities of gas at reasonable prices to make upstream investments viable. There are over 2500MW of installed thermal electricity capacity with an additional planned capacity of 2025MW. Majority of these plants are CCGT using LCO, Distillate fuel or Gas as fuel.

Gas is, however, the preferred fuel choice for the majority of these power plants for economic, technical and environmental reasons, according to the interviews with IPPs [TICO-IPP, TAPCO-IPP; SAPP-IPP]. IPPs in Ghana are much particular of secured and reliable gas supply at economically viable rates compared to competing fuels (LCO). The choice between the duration of contracts between IPPs and gas producers/suppliers will depend on the specific situations of both parties.

Whereas long-term contracts in gas trades are increasingly becoming irrelevant because of their rigid nature, short-term trades introduce flexibility to contracting parties. However, will downstream consumers in Ghana prefer short or long-term contracts with gas producers/suppliers? Long-term contracts minimise transaction costs between parties (Neumann and von Hirschuasen, 2015). They guarantee upstream producers/suppliers projects, a downstream buyer and financial commitments over a long-term period.

The MBM will lead to shorter gas contracts with flexibility (Neumann and von Hirschausen, 2015) but as industry structures move from SBM to MBM, long-term contracts lose their value (Neunmann and von Hirschausen, 2015). The introduction of short-term contracts in Ghana's nascent gas industry because of adopting the MBM will have minimal implications for upstream gas producers/suppliers as this deepens competition in gas supply. However, investors are not as bothered about competition as they are about the protection of their investments, which MBM cannot provide. Short-term contracts will facilitate transactions in FSRU LNG between gas traders/suppliers and downstream consumers.

At what point will downstream consumers switch a supplier. If that happens, what happens to gas producers? When the consumers' short-term contracts with gas producers/suppliers expire, both parties can renew their contracts or switch if there are more favourable terms with other parties or renegotiate existing contracts. When alternative fuels (LCO and distillate fuels) are cheaper, consumers will switch fuels, which is most unlikely in the short-term because, historically, gas prices are relatively cheaper than LCO.

Gas producers/suppliers require protection from arbitrary customers switching from consumers. Investments in storage facilities allow lower-priced gas to be stored and sold when prices increase. The MBM will facilitate investments in storage infrastructure. Ghana, however, is currently under a stressed natural gas demand and requires a supply security than consumers switching suppliers.

5.4.0. Open Access to Pipelines and Essential Infrastructures in Ghana

There are efforts to encourage the common use of the existing limited infrastructures in transmission pipelines whilst encouraging further investments. The Energy Commission, Natural Gas Transmission Access Code and the West African Gas Pipeline Access Code Part A and B seek to establish open access and transparent/non-discriminatory third party access to both transmission pipelines [Midstream-EC; Midstream-WAGPCo]. A Natural Gas Transmission Utility (NGTU) was established by Energy Commission to operate as an independent pipeline transmission operator, whilst WAGP Authority regulates and enforces the WAGP Access codes [Midstream-EC; Midstream-WAGPCo].

The GNGC Transmission pipeline network operation is still under contention between GNGC and BOST as to who should be the operator. According to an interviewee BOST is recognised as the NGTU; however, GNGC owns the pipeline and is unwilling to relinquish it to BOST [Midstream-EC]. Resolving the issues of who should be the NGTU and enforcing effective open access regulations to existing pipeline infrastructure are crucial to reducing regulatory risk [IOC-ENI-Ghana], especially with the introduction of the MBM.

The MBM will require effective third party access to transmission network and other essential infrastructure. For effective MBM, access to the transmitting pipeline must be guaranteed (Marston, 1991). The use of the same transmission pipelines by different entities on a fair and equal basis is at the core of transiting from SBM to MBM (Kessides, 2004; Hallack and Vazquez, 2014).

Open access to transmission pipelines is necessary when there are many players and high intensity of trading (Kessides, 2004) and when there is excess gas supply capacity arising from old investments. There is a growing number of industry players and potential for further growth in the upstream and downstream segments; therefore, a non-discriminatory access to the transmission pipeline is necessary if they are to compete favourably (Kessides, 2004). In addition, there is significant need for infrastructure in gas supply, pipelines and downstream consumption. Most importantly, there are several problems with gas non-payments from consumers such as VRA and ECG [Midstream-WAGPCo].

How can an effective Third Party/Open Access transmission system be established in Ghana's nascent gas industry? The first option is to separate the network owner and operator from participating as suppliers in the competitive segments and to retain the benefits of vertical integration, the asset owner should be allowed to charge transmission tariffs based on cost-recovery prices (Newbery, 2001). In the MBM, there is likely to be monopoly power abuse in favour of asset owners over the other players. Separating GNGC transmission network from GNPC upstream gas aggregation role or allowing fair access tariff for WAGP and GNGC transmission pipelines are required for effective third-party access and transition to the MBM.

Gas transmission pipelines are either regulated through a set of access codes applied to all users termed regulated access codes (practiced in EU) or through each pipeline network defining its services separately based on negotiations with the user, termed negotiated access code (practiced in USA) (Hallack and Vazquez, 2014; Kesside, 2004). Network access rules for the GNGC transmission pipeline and WAGP are based on a set of access codes applied to all users. The first step is to ensure fair access and fair access charges to the gas transmission network (Newbery, 2001). As the incumbent owner of the transmission pipeline can deter entry by capturing all capacity rents, access tariffs on the GNGC and WAGP transmission pipelines must be fair to all players whilst meeting the needs of the network owners.

Access charge design must, therefore, include efficiency and investments decisions while enabling the owner of the network to remain financially solvent. Access tariffs should be high enough to be compensatory and yet not so high as to preclude efficient operations by the entrant. Kessides (2004) identified two ways to offer effective access tariffs:

- Baumol-Willig efficient component pricing rule or parity pricing and
- Laffont-Tirole global price cap rule.

For the efficient component-pricing rule or parity pricing, the holder of the transmission pipeline is allowed to charge as much for its services as it would earn from providing them itself. The Laffont-Tirole global price cap rule, on the other hand, ensures that the profit of the integrated incumbent is an increasing function of the access charge and the final retail price. The regulator would have to take into account the balance between the two access tariff processes to determine the access charge. Albeit, a hybrid model can be developed with the objective of promoting productive, allocative efficiency, pro-poor and rural-led gas infrastructure policy development (Kessides, 2004).

The second step is to design effective access regulations, which set network regulations with realistic perspectives of being implemented. The motive of an effective open access to the transmission pipeline is to ensure that the infrastructure owner has no right to discriminate against legitimate users in offering three basic services: transportation of gas between two points in a determined point in time, transportation of gas between two regions and transport and line-pack storage[31] of gas (Hallack and Vazquez, 2012).

Without good access rules, efficient competition will be difficult to implement in the competitive segments especially when the infrastructure owners are also players of the gas supply and distribution sectors (Joskow, 1998 and Kessides, 2004). The use of the network by a single or multiple users determines the rules of the industry (Hallack and Vazquez, 2014). This requires effective institutional arrangements and efficient network rules and implementation (Hallack and Vazquez, 2014) which, in the case of Ghana, are the ex ante network access regulatory codes.

Institutionally who determines the rules of use? Open access requires an independent regulator (European Commission, 2013). The independent operator, the NGTU, will coordinate the transmission access usage. The NGTU will provide a stable market condition required to attract funding for long-distance pipelines, develop a regulatory framework to ensure competition and non-discriminatory access to pipelines whilst providing incentives for increased infrastructure investments and meeting the needs of vulnerable consumers (European Commission, 2013; Correlje et al., 2013).

Gas owners will, therefore, acquire transportation contracts from the NGTU, which specifies the volume to be transported from an injection point to a withdrawal point and metered to verify volumes (Hallack and Vazquez, 2014). Property rights will be defined by the NGTU in different ways: injection,

[31] Line-pack storage of gas is define as the amount gas available in a pipeline and the gas can be stored in large quantities in high pressures in the pipeline.

withdrawal, flow and pressure management, nomination, exclusion and many more (Glachant et al., 2014).

The NGTU, on the other hand, must choose between common carriage and contract carriage rights, which define the basic frame of infrastructure usage, the injection/withdrawal rights and exclusion rights for the users. In the common carriage system, injection/withdrawal rights are offered ex ante to all potential users of the pipeline. In the contract carriage, the set of user rights to injection/withdrawal is defined ex ante and restricted to those who have long-term contracts with the pipeline owner or the operator (Glachant et al., 2014).

What are the network access rules? Network access rules are categorised under two broad headings: first, the mechanism allocating rights of usage among all potential users and second, the definition of the actual transmission service characteristics corresponding to this usage right (Glachant et al., 2014). They are, also, known as balancing rules[32] and localisation of entry and exit of the flow rules[33] (Hallack and Vazquez, 2014).

Capacity allocation rights are categorised into implicit and explicit rights. Under the implicit capacity allocation rights, the market outcome of the transmission capacity allocation and the market outcome of the commodity trade are voluntarily coordinated ex ante. By this, all gas owners with wholesale gas volumes can access the transmission pipeline in real time (Glachant et al.,

[32] Balancing rules defines how long the shipper/supplier can maintain the difference between injection and withdrawal from the network.
[33] Localisation rules defines where natural gas can be injected and withdrawn.

2014). The explicit capacity allocation rights, however, involve an independent and separate transmission market in which the transmission capacity is traded and priced for itself, disregarding who owns the gas commodity. It is up to each gas commodity owner to ensure how to use the pipeline (Glachant et al., 2014).

Where the market has not yet been developed and transmission network capacity is limited, will open access attract new investments in the gas industry in Ghana? This depends on how the current gas transmission network is being used; that is, the past offer and demand of the pipeline and how it might be used in the future, which in turn influence the expectation of possible usage of new infrastructure (Glachant et al., 2014). The investment path corresponds to certain allocation of decision rights: how much extra pipeline capacity is required and at what cost, volume and tariff?

The NGTU is responsible for operating and increasing transmission pipeline investments in Ghana. Strong access rights generally encourage higher investments (Glachant et al., 2014). A network only company has the incentives to expand infrastructure once the demand exists because every gas transported increases profits (von Hirschhausen, 2008). Unlike a network only company, which operates a small pipeline, an integrated company can raise funds using its balance sheet and provide guarantees and securities.

An allowable ROR is used by the US Federal Energy Regulatory Commission (FERC) as an instrument to attract investments in pipeline infrastructure as FERC calculates Return on Investments (ROI) to recover the cost of prudent operation, depreciation, taxes and a return on the capital invested subject to an overall ROR. Transmission tariffs are negotiated between the transmission asset owners and asset users and are regulated by Public Utilities Regulation Commission of Ghana [Downstream-PURC].

In determining the appropriate risk-adjusted cost of capital and the appropriate rate base, the weighted cost of capital is determined by estimating the appropriate rate of debt, the cost of equity and the capital structure-gearing ratio. ROR was, thus, used to secure long-term network infrastructure investments and medium-term infrastructure adequacy. ROR is, however, criticised for triggering overinvestment and an inefficient use of capital and labour (von Hirschhausen, 2008). Other regulatory schemes such as Incentive regulation and performance-based ratemaking in which pipeline owners share efficiency gains with users via lower prices are recommended.

What are the benefits of an open access system in Ghana's nascent gas industry? The open access system will mitigate the incentives of discriminating against competitors and increase equal access to the market (Hallack and Vazquez, 2014). However, an open access regime is not a priority in the nascent gas industry as a lack of equal and transparent third-party access will create enormous entry barriers for new players and would severely hamper the development of an effective MBM (Nowak, 2010).

5.5.0. Unbundling Natural Gas Services in Ghana

Unbundling means completely separating midstream infrastructure from upstream producers and downstream consumers and electing an independent operator to operate the transmission network (Juris, 1998).

Unbundling will involve maintaining competition in the production, services and retail segments of the gas industry and regulating the essential facilities (Correlje and Groenewegen, 2006) for the common use of all participants (Hallack and Vazquez, 2014).

Unbundling natural gas services in Ghana will involve altering the SBM of GNPC and separating gas supply from the pipeline transmission network and enabling the full operation of the MBM. Unbundling, essentially, means separating GNPC aggregating role from upstream suppliers and GNGC infrastructure ownership (the GPP and the transmission pipeline) and allowing different entities to provide each service separately. In the interview with the Ministry of Energy, critical concerns where raised against unbundling gas services in Ghana:

> *'Does it make sense to unbundle gas services in Ghana? Does it make sense to let BOST operate the gas transmission lines instead of GNGC to avoid possible pipeline access discrimination and possible abuse of monopoly power'?* [Min-Energy].

The Ministry of Energy based their arguments on two assumptions:

- Assuming GNPC is the sole aggregator and owner/shipper of gas in Ghana (SBM), the issue of access discrimination would be non-existent since there will not be any other gas owner in the country to discriminate against [Min-Energy].
- Assuming GNPC is not the sole aggregator/shipper of gas in Ghana, rather, there are multiple gas owners and GNPC is still the owner of gas

infrastructure (GPP and GNGC transmission pipeline), the issue of access discrimination will not be plausible due to adequate available pipeline capacity. Since the regulator determines the tariffs and service charge, the issue of monopoly would not exist [Min-Energy].

Scenario A: Assuming GNPC is the sole gas aggregator and the only gas owner/shipper; will unbundling be necessary? Having GNPC act as the sole upstream gas aggregator has some advantages to the development of the nascent gas industry in Ghana. GNPC serves as the upstream partner to all gas projects and is the de facto aggregator of upstream gas in the gas sales contracts. The SBM allows GNPC to provide financial guarantees for the commercialisation of gas projects (e.g the SGP) and makes it possible to shield financiers of upstream gas investors from market risk and retail level regulatory risk. This reduces financing cost and makes gas investment projects commercially bankable in Ghana. Such a model helps maintain a unified domestic gas price downstream by delivering average gas prices and cross-subsidization of gas prices. Government control of gas markets has often led to distorted prices, inefficient operations and deteriorating infrastructure that could be avoided through effective regulations.

Additionally, Lovie (2000) strongly opposes SBM of GNPC, as it invites corruption, weakens payment discipline and imposes large contingent liabilities on government (GNPC). The SBM may show upward bias from interest groups pushing GNPC to serve as a financial guarantee for additional gas supply capacity. For instance, the recent FSRU – LNG plant required GNPC to serve as an off-taker. As an interviewee recounted, soon, there will be another gas project that will require GNPC to provide financial guarantees, and this will, in the long-run, overburden the responsibilities of GNPC and drift them away from their core mandate of being a national oil company [IOC-ENI-Ghana].

Moreover, GNPC having to provide financial guarantees as off-takers for most of these gas projects creates contingent liabilities for GNPC which is supposed to step in when downstream consumers (VRA and ECG) are unable to honour their obligations of gas purchases. These implicit and explicit contingent liabilities can undermine GNPC's creditworthiness and their balance sheets may deteriorate.

The current structure can, as well, undermine the development of the nascent gas industry in Ghana since a state-owned company (GNPC) which leads industry development without a strong profit motive can become a major disadvantage when expanding new infrastructure and introducing innovation. The SBM, with GNPC as gas owner, weakens the willingness of state-owned gas consumers such as VRA to pay for gas purchases. This will worsen the current hold-up and lock-in debt problems of VRA in paying GNPC. These state-owned institutions dominating the gas value chain in Ghana (GNPC, VRA and ECG) are unlikely to take politically unpopular decisions (Lovie, 2000). This usually results in poor payments for gas purchases and could lead to poor liquidity in the gas industry in the long-run.

The SBM allows government intervention in influencing gas prices and the allocation of cash proceeds (profits) from further investments to improve the gas value chain. However, cash is diverted into illegal purposes such as funding political campaigns, especially in instances where there are high levels of corruption (Lovei, 2000). Finally, the SBM may be used by pressure groups to indefinitely delay government's move towards the next step of unbundling (Lovei, 2000).

Scenario B: Assuming there are multiple gas owners but GNPC leads the SBM and are the infrastructure owners, guaranteeing third-party access to essential infrastructure, will unbundling still be necessary? There is the likelihood of abuse of market power by GNPC in infrastructure access, and this will limit effective competition. It is better to skip the SBM altogether for the MBM (Lovei, 2000) as the MBM will drive the market to unbundle (Cramar, 1991). The MBM will introduce other gas owners who will not require only GNPC to provide financial guarantees for gas agreements. GNPC will, thus, not shield gas producers/suppliers from regulatory/market/political risks. Meanwhile, the lack of a direct contract between gas producers and consumers will still undermine payment discipline. Private partners, as well, based on market performance, can influence decisions for new gas supply infrastructure.

Unbundling gas supply from transportation services and consumption presents two distinct markets: the gas supply/trade market where participants trade natural gas as a commodity and minimise supply and price risk and the transportation services market where participants trade transportation services for shipping gas through the pipeline (Juris, 1998). This will call for the use of intermediaries (traders and shippers) and spot markets that promote efficient pricing and minimise transaction costs.

According to one interviewee [Midstream-EC], two main concerns are raised supporting the implementation of unbundling in Ghana. Energy Commission's Act 541 (2007) mandates that a Natural Gas Transmission Utility (NGTU) will be responsible for the operations of natural gas transmission pipeline services, and BOST is the licensed NGTU. The reasons according to the interviewee are two in folds [Midstream-EC]:

- To prevent pipeline access discrimination to third party and
- To avoid monopoly power abuse and promote competitive pricing of gas by allowing more players into the market.

GNGC, the owners of the GPP and transmission pipeline, is a subsidiary of GNPC; but the gas owners cannot be the infrastructure owners so BOST should operate the GNGC transmission pipeline. Again, the transmission pipelines will have to be unbundled from upstream operations and downstream consumers. Unbundling will mean separating pipeline operations from gas aggregation/ownership to processing and consumption; that is, separating GNPC and GNGC from the pipeline transmission business.

WAGPCo will need to offer their pipeline services to two key markets: external shippers bringing gas from Nigeria into Ghana and the internal market of transporting gas between different consumers within Ghana. Haucap (2007) recounted two benefits of unbundling: decrease in the network operators' incentives to discriminate between incumbents and new entrants and increase in the network operator's incentive to invest in the transmission capacity.

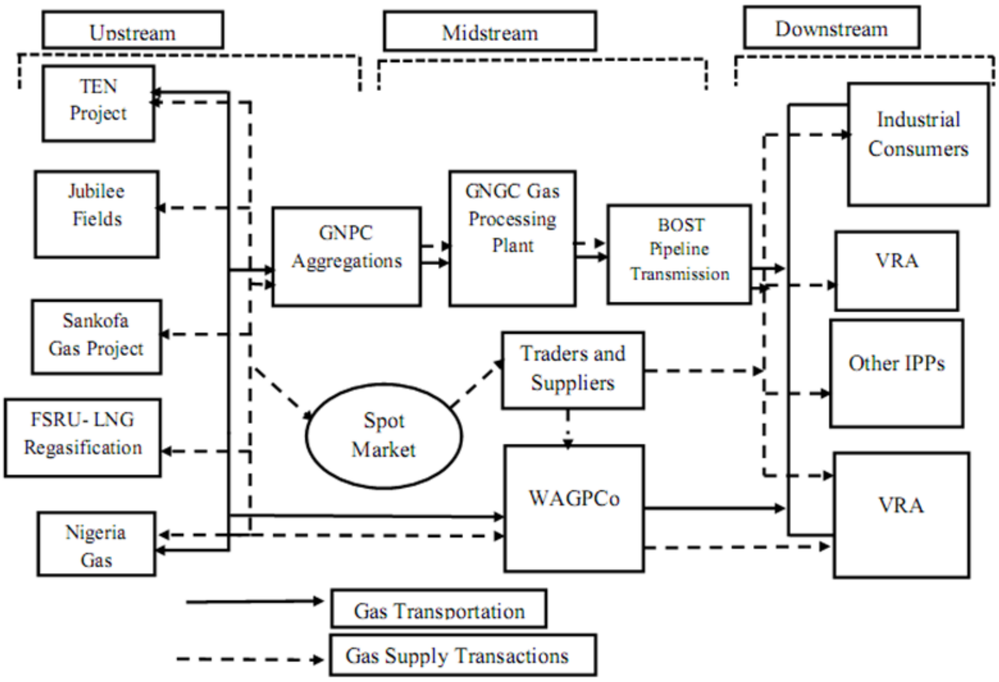
An unbundled gas industry structure is illustrated on Figure 14. Multiple upstream gas buyers and multiple gas supply sources include domestic production, LNG and Nigerian Gas. The role of GNPC as an upstream aggregator will be unbundled from the midstream infrastructure, i.e. GNGC transmission services. BOST will in turn, be the NGTU and an independent operator of GNGC pipeline and other pipeline networks.

From Figure 14, the proposed structure has three issues that will emerge in Ghana: allowing multiple gas owners, unbundling gas transmission from production and diversifying downstream gas consumption. By this, the GNPC-GNGC-VRA single buyer model and the N-Gas-WAGP-VRA model will be completely unbundled. Several gas owners will, as a result, be introduced through bilateral and trilateral long-term and short-term contracts with short-term contracts being more prominent.

The FSRU can serve multiple gas traders and suppliers. Gas consumers can, as well, arrange for their own LNG. Pipeline transmission will be unbundled from upstream production/supply and both GNGC & WAGP transmission pipelines will operate on open access basis. Additionally, the FSRU will operate as a tolling facility because it is also an essential facility (bottleneck facility) (von Hirshhausen, 2008).

In addition, the spot market concept will emerge because of competition; a well-functioning spot market concentrates trading in a location (Juris, 1998). Even in the European markets, there are very few effective spot markets. However, the spot market concept introduces flexibility which minimises supply and price risk in both short and long-term transactions.

Figure 14: Unbundled the Natural Gas Industry in Ghana



Source: Adapted from Juris (1998).

The spot prices will reflect the economic value of natural gas in Ghana, which is a good signal to potential investors. Different duration of gas trading contracts such as short-term contracts for the supply of up to one month, medium-term contracts for the supply of one month to twelve months and long-term contracts for the supply of more than one year will be introduced.

Gas traders will be connected to gas producers and consumers or simply arrange gas sales and transportation deals among various parties. Gas traders are not subject to any regulatory oversight (Cramer, 1991). In the wholesale gas markets, gas is purchased for resale among traders, suppliers, pipeline companies and distributing companies. The retail market offers gas sales for end users with transactions occurring between suppliers and small and large-scale consumers (Juris, 1998).

What are the transaction cost implications of unbundling the gas industry in Ghana? A concern to policy makers in the gas industry in Ghana is how to balance the structure of the gas industry to a sufficient degree of stability to bring about investments. The transmission pipeline segment is seen as a natural monopoly because of economies of scale and scope, the fixed costs of the pipeline construction and the relatively low variable cost of their operation, which are common pool or essential facilities (Hallack and Vazquez, 2014; Correlje and Groenewegen, 2006). These assets need to be regulated to allow open access and avoid abuse of dominant market position (Correlje and Groenewegen, 2006).

The evolution of the spot market concept through unbundling will see multiple gas buyers introduce shippers/traders and several downstream natural gas consumers. Since more buyers and sellers reduce the relationship specific investments, this can lead to lower transaction costs and reduce the chances of market power control (Arora, 2012). It will, also, prevent opportunistic behaviours of trading partners who are looking to take advantage of the relationship leading to the hold-up problem where parties are locked in the inefficiencies of their trading partners (Arora, 2012).

In sum, unbundling will provide a very complex gas industry structure, which will require well-skilled personnel to regulate and manage. However, such personnel are absent in Ghana. Also, an unbundled or a competitive gas structure in Ghana will be difficult to implement as there is, still, a limited number of credible gas off-takers and a lack of sufficient infrastructure and regulatory credibility. Simply put, the nascent gas industry in Ghana is too small for unbundling.

5.6.0 Structural Evaluation of the Gas Industry in Ghana

Natural gas industry structural reform processes in all countries have been slow and tortuous and require tailoring to fit the current political and economic climate (Shell International and DRC, 2017). The debate of identifying the best-fit structural model for the nascent gas industry in Ghana concerning whether to proceed with the existing SBM or switch to MBM are evaluated based on the objectives of the industry. These objectives include reaching more gas consumers, making gas affordable to consumers, having a reliable supply of gas, having a viable supply chain, attracting investments and investors, reducing risks, being easy to implement, being easy to regulate, reducing asset specificity and reducing uncertainties (Eberhard, 2007). The variables for the evaluation criteria are compared to the structural models based on their impact and effectiveness on maintaining a viable gas industry in Ghana.

The World Bank (2018) RISE project – Regulatory Indicators for Sustainable Energy – evaluations criteria is based on three areas: energy access, energy efficiency and renewable energy, and provides the guiding evaluation principles for structural evaluation in the nascent gas industry in Ghana. RISE classifies countries into a green zone of strong performers in the top third, a yellow zone of middling performers and a red zone of weak performers in the bottom third. The nascent gas industry structural evaluation criteria for Ghana classifies the green zone as strong performances and effectiveness, yellow zone as middle performance and effectiveness and the red zone as weak performance and less effectiveness.

The SBM maintains a weak viability of natural gas supply chain with limited number of gas suppliers. As a result, gas supply reliability is weak, especially when existing domestic gas production volumes are diminishing. There is, however, a strong gas demand certainty for gas in power generation, with potential demand in other small-scale to large-scale consumers. SBM presents high investment risks, which require high regulatory supervision in determining tariffs and gas prices indicating weak performance. Asset specificity is high with lower asset intensity and reuse and high frequency of transaction with recurrent exposure to a single buyer, which increases uncertainty in default rate indicating weak performance. As a result, gas affordability is high, indicating weak performance in the SBM.

Nonetheless, the SBM has a strong appropriateness for the existing market maturity since this is a nascent industry, indicating middle performance. SBM is considered an appropriate industry structure for the maturity stage of the nascent gas industry in Ghana, which indicates strong performances in implementation. Nevertheless, it is an unsuitable structure considering business viability because of the hold-up and lock-in problems and the high inefficiencies indicated on the evaluation Table 29. SBM displays more red-alerts, which indicate weak performance on high investment risk, higher regulations required, higher asset specificity, uncertainties and transaction frequency.

MBM: A indicates middle performance throughout the evaluation criteria except in regulatory supervision which requires the selection of large-scale wholesale gas buyers based on their ability to pay economic tariffs, size and consumption capacity; this indicates a weak performance. Aside that, the supply chain viability, supply reliability with additional gas suppliers, demand certainty to power plants and additional consumers and a complex structure to implement gas affordability is middle performance compared to SBM. This is because new suppliers depending on their cost introduce additional gas sources. MBM: A generally indicates middle performance compared to SBM, which indicates weak performance.

Appropriateness for existing market maturity for MBM: A indicates middle performance because SBM is still on course. MBM: A provides more advantages to the nascent gas industry in Ghana compared to SBM. With multiple players, asset specificity will reduce, transaction frequency to single parties will reduce and uncertainties will remain low compared to SBM.

MBM: B appears to be the most appropriate and suitable structural arrangement for the nascent gas industry in Ghana. MBM: B indicates a strong performance in viability of gas supply and reliability, a middle performance in gas demand certainty, investment risk and complexity of implementation and a strong performance in regulatory supervision, which implies shifting reliance on industry self-regulations.

Table 29: Industry Structural Models Evaluation

Evaluation Criteria	SBM	MBM A	MBM B	Unbundled
Viability of supply chain	Weak	middle	strong	strong
Reliability of gas supply	weak	middle	strong	strong
Demand certainty	strong	middle	middle	middle
Investment risk	weak	middle	middle	middle
Complexity of implementation	strong	middle	middle	weak
Regulatory supervision	Weak	weak	strong	middle
Affordability of gas supply	Weak	middle	middle	middle
Appropriateness for existing market maturity	strong	middle	middle	weak
Asset Specificity	weak	middle	middle	middle
Transaction Frequency	weak	middle	middle	middle
Uncertainties	Weak	middle	middle	middle
	Middle Performance			Weak Performance
	Strong performances			

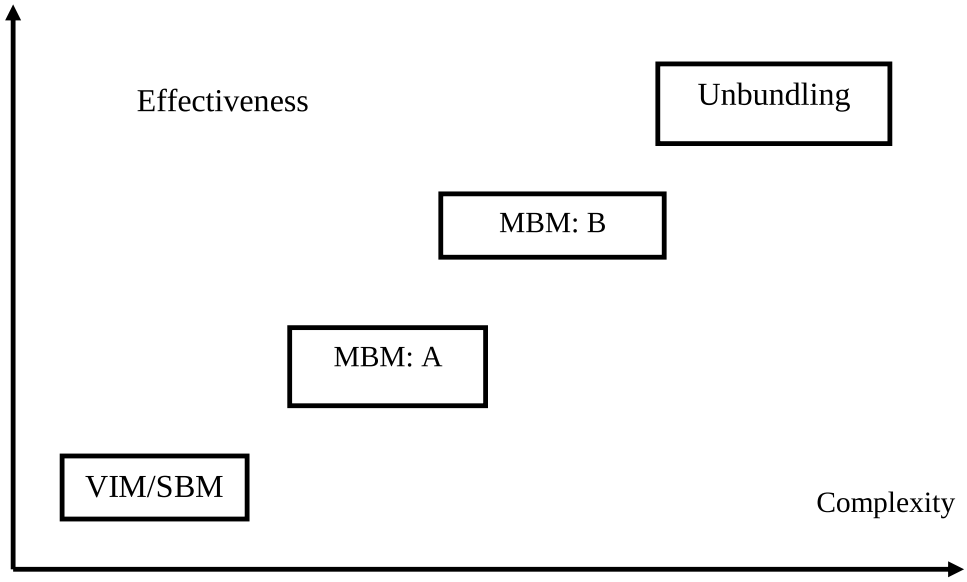
Source: Adapted from World Bank (2018); Eberhard, (2007); Mckinsey (1993).

MBM: B also indicates middle performance in investment risk due to higher certainty of matching gas supply with demand as gas affordability remains relatively low compared to MBM: A. the current SBM can be skipped completely to MBM: B since maturity appropriateness, asset specificity, transaction frequency and uncertainties are middle performance. This will support the argument of two interviewees for a more competitive gas industry structure for Ghana [Midstream-EC; IOC-ENI-Ghana].

Unbundling would have been the most appropriate structure since this indicates strong performance in viability and reliability of gas supply. Middle performance in investment risk, gas affordability, regulations, asset specificity, transaction frequency and uncertainties. However, complexity of implementation and appropriateness of existing market maturity of an unbundled structure in the nascent gas industry in Ghana indicates weak performance, making this structure inappropriate and an unsuitable structure. This notwithstanding, it can be considered at a later stage.

In essence, SBM is less effective and less complex in implementation but as the industry matures and develops, MBM: A and B should be considered because of increases in effectiveness and implementation complexity until the final model structure of unbundling is reached when the industry fully matures as Figure 15 indicates.

Figure 15: Structural Arrangements for the Gas Industry in Ghana



Source: Adapted from Bhattacharyya (2011).

In sum, selecting the best-fit industry structure for the nascent gas industry in Ghana requires a rebalancing act. MBM: B is considered more appropriate for the nascent gas industry in Ghana; in that, it is relatively effective and less complex to implement as indicated on Figure 15. It, also, prevents the hold-up and lock-in problems of the SBM with high investment risk and low viability of the gas supply chain and gas supply reliability. Besides, MBM: B displays low asset specificity whilst increasing asset intensity promotes shorter-term contracts to reduce frequent transactions to single buyers. This reduces uncertainties; thereby, reducing overall transaction cost in the nascent gas industry in Ghana.

5.7.0. Chapter Summary

In conclusion, three structural models are considered but none of the models will be able to offer a one-size solution to the structural problems facing Ghana: encouraging investment upstream and mid-stream, providing cost effective gas supply to consumers, ensuring supply chain viability and managing risks. SBM causes hold-up and non-payment issues but can offer cheap supply through cross-subsidies. This, in turn, can attract investments upstream through long-term contracts. MBM: A, on the other hand, reduces hold-up issues but non-payment issues remain. In this module, small consumers are likely to get high cost supply and suppliers may become opportunistic – selling gas to high price markets causing supply reliability issues.

MBM: B, as well, offers flexibility to suppliers but the lack of long-term credible contracts will not allow upstream investments to materialise. Gas prices are likely to go up, particularly for small users. The market balancing issue will appear and the market can become risky. Non-payment by consumers of gas will remain until IPPs and large users can have access to own markets. However, MBM: B is suitable as a structural model for the nascent gas industry in Ghana compared to the SBM, MBM: A or unbundling.

CHAPTER SIX

BUSINESS VIABILITY OF THE GAS INDUSTRY IN GHANA

6.0. Introduction

Chapter six (6) discusses the second objective of the study: to examine the business viability of the supply components of the gas industry for infrastructure investment decisions in Ghana. The chapter is divided into three parts. The first section considers the integrated cash flow model and the input data and assumptions of the study, the second section focuses on the static analysis of the study while the third section looks at simulation and sensitivity analysis and the conclusions.

Establishing the viability of the various supply components of gas-to-power value chain is part of a systematic and an all-encompassing analytical framework and risk-reward approach to assert the attractiveness and financial viability of the nascent gas industry in Ghana (Razavi, 2007). Netback analysis established the power sector in Ghana with the highest economic and strategic value in the domestic utilisation of natural gas (Ministry of Energy - Ghana Gas Master Plan, 2015). Fritsch and Poundineh (2016) identified unfavourable investments climate as a major challenge in attracting infrastructure investments into the nascent gas industry in Ghana.

The integrated cash flow model generates net present values (NPVs) which are key measures of the financial viability of the four natural gas supply components (Leuch, 2012). The NPV measures the actualised net revenues of the projects and indicates the viability of the projects to investors (Razavi, 2007). Simulation and sensitivity analysis are performed on the various project components to reveal and ascertain the project risk and the variability of the risk impacts. The integrated model is built on these four gas supply components of the cash flow model in Microsoft Excel as indicated in Appendix 3:

- Component 1: Upstream production of natural gas (PSC terms)
- Component 2: Natural Gas Processing Plant (GPP)
- Component 3: Natural Gas Transmission Pipeline
- Component 4: Combined Cycle Gas Turbine (CCGT)

6.1.0. The Integrated Cash Flow Model

Integrated gas value chain analysis consist of linking an upstream gas production project through a processing plant or directly to a transmission pipeline network to a downstream consumer (a CCGT plant). This was used to develop an analytical framework (Herath and Malhotra, 1996; Leuch, 2012) for the study of the gas industry in Ghana. The following presents the technical and cost aspects of the integrated gas value chain. The cash flow components will generate a model to serve as a tool for the identification of risks/uncertainties and the opportunities in the gas industry in Ghana (World Bank, 2004).

6.1.1. Upstream Natural Gas Production: The Sankofa Gas Project

The four integrated cash flow components are built around upstream natural gas production such as the Sankofa Gas Project (SGP). The SGP produces small volumes of associated gas and large volumes of non-associated gas. Essentially, the non-associated gas is transmitted to a CCGT for consumption in electricity generation. The associated gas requires the Gas Processing Plant (GPP) to separate lean gas (methane) from the other gases such as ethane, butane and propane into Liquefied Petroleum Gas (LPG) for household consumption. The methane (lean) gas is transmitted through a pipeline network to the CCGT plant. The total cost of the SGP is estimated at US$7.9billion (World Bank, 2015).

6.1.2. Natural Gas Processing Plant: GNGC

Upstream produced associated gas requires treatment to remove impurities to meet the quality standards for transmission and downstream consumption (Melton, 2015). The Gas Processing Plant (GPP) separates the raw gas into lean gas (methane) for the CCGT consumption and LPG (ethane, butane and propane) for household consumption (World Bank, 2004).

The lean gas is transmitted through a 114km GNGC pipeline and LPGs are sold and transported via loading trucks to meet 60% of domestic demand in Ghana [Midstream-GNGC]. The GPP is part of the Western Corridor Gas Infrastructure Development Project consisting of a 45km offshore pipeline, 150,000MMBtu/d capacity GPP, a 114km onshore pipeline and a Natural Gas Liquids Export System [Midstream-GNGC]. The Infrastructure Project is funded by a US$1billion loan facility (part of a US$3billion loan facility) secured from the Chinese Development Bank (CDB) in 2013 by the Ghana government.

6.1.3. Natural Gas Pipeline Company: The case of BOST

The GNGC gas transmission pipeline is a 114km pipeline with a 20inch inside diameter and consists of pressure stations, a gas distribution station, a terminal station, and two set of block valve stations. This pipeline is part of the "Western Corridor Gas Infrastructure Development Project" and is estimated to cost US$310million (GNGC, 2011). The pipeline is to convey both processed gas from the GPP (all associated gas) at Atuabu[34] and the non-associated gas from an Onshore Receiving Facility (ORF) point from Sanzule[35] to CCGTs at the Takoradi-Aboadzi power enclave in the Western Region of Ghana. It is assumed that the transmission pipeline is operated as a separate gas supply component and a separate business unit. The NGTU is assumed as the independent operator of the GNGC pipeline.

6.1.4. CCGT Power Plant: The Takoradi International Company

The natural gas from the SGP upstream is slated for CCGT utilisation in electricity generation. Electricity can be produced from generators driven by gas turbines or steam turbines with heat from natural gas (World Bank, 2004). It is assumed that the Takoradi International Power Company (TICO), an IPP in Ghana, generates electricity using CCGT with the upstream gas on an installed capacity of 1100MW. This is a GE (General Electric) gas turbine and steam turbine generator [Downstream-VRA]. The TICO plants currently account for about 11.6% (330MW) [TICO-IPP] of installed thermal electricity

[34] Atuabu is a town in the Western Region of Ghana where the gas processing plant is located
[35] Sanzule is a town closer to Atuabu where the Onshore Receiving Facilities are located

generation capacity but with the 1100MW capacity, this will be the largest thermal plant in Ghana.

The plant has a dual fire capacity, which can run on Light Crude Oil (LCO) or gas. World Bank (2013) noted that, usually, small power producing units between 250-5,000kW have overall efficiencies of 25%-35% while larger power plants may have overall efficiencies in excess of 50%. But a combined cycle producing heat and power at such a large plant with capacity of 1100MW would have a total energy efficiency of about 48% (World Bank, 2013).

6.1.5. Objectives of the Integrated Cash Flow Model

The objective of building the integrated cash flow model for the nascent gas industry in Ghana is to determine the business viability of the various supply chain components of the gas industry, perform static analysis on the projects NPVs and undertake simulation and sensitivity analysis on the projects risk factors. This section seeks to answer the following questions:

- How viable is upstream production of natural gas?
- How viable is the GPP?
- How viable is the Transmission pipeline?
- How viable is the Combine Cycle Gas Turbine?

6.2.0. Input Data and Assumptions for the Integrated Cash flow Model

Non-associated gas prices as agreed in the Gas Sales Agreement (GSA) from the World Bank (2015) report is US$9.8/MMBtu. The gas royalty rate is 7.5% from the SGP, producing on average 54BCF/per annum. An estimated

SGP total capital cost of US$7.9billion for 20years is assumed and it is the same as the World Bank estimated SGP capital cost. The GPP processing tariff of US$3/MMBtu and LPG sales price of US$320/mt are obtained from [Midstream-GNGC] with methane gas volumes of 97% and LPG, 3% received from the upstream. The transmission pipeline tariffs of US$2.28/MMBtu are also obtained from [Midstream-GNGC] as indicated on Table 30.

Table 30: Assumptions and Output Data for Integrated Cash Flow

Upstream Natural Gas Production		**Total Project Cost**
Non-associated natural gas prices Gas Volumes/per annum Gas Royalty Rate	US$9.8/mmbtu 54BCF 7.50%	US$7.9billion
Gas Processing Plant		
Gas Processing Tariffs LPG Selling Price Methane Gas Quantities LPG Quantities	US$3/mmbtu US$320/mt 97% 3%	US$733.3million
Transmission Pipeline		
Transmission Tariffs Estimated Transmission losses	US$2.28/mmbtu 5%	US$390.8million
CCGT Power Plant		
Gas Prices Electricity Prices Plant Efficiency Plant Load Factor Gas Requirement	US$8.7/mmbtu 0.09cent US$/kWh 48% 90% 43.95BCF/year	US$1.045billion
Discount Rate	10%	

Source: Data from Interviews.

The GPP has a capital cost of US$385.4million as obtained from (GNGC and SINOPEC, 2011). A US$374.4million operating cost assumed for the GPP [Midstream-GNGC]. A total cost of US$733.3million is estimated for the 20years GPP lifespan. GNGC and SINOPEC (2011) contract documents have a US$280million capital cost for the 114km transmission pipeline and a

US$110.8million operating cost estimated for the 20years operating period of the pipeline [Midstream-GNGC]. Therefore, an estimated US$390.8 million pipeline cost is assumed for the transmission pipeline project.

The 1100MW Combined Cycle Gas Turbine is constructed to fully utilise the domestically produced natural gas. The plant cost is US$1.045billion. The 1100MW plant capacity could be separated into four smaller unit plants (275MW each) but is assumed as a single unit plant. Current wholesale electricity prices of US$0.09cent/kWh [Downstream-PURC] is assumed for the CCGT and an average domestic gas purchase price of US$8.7/MMBtu are used [Downstream-VRA]. A discount rate of 10% is assumed for the integrated cash flow analysis, as was the case for the World Bank (2015) economic and financial analysis for the SGP as indicated on Table 30.

6.3.0. Static Analysis of the Gas Industry in Ghana

The static analysis considers the investment costs of each of the various supply components of the natural gas value chain (Zhu et al., 2016). This section takes a static analysis approach to understanding the financial interconnection between the various components through an integrated cash flow model (Weijermars, 2010) to formulate hints for identification of unfavourable conditions and opportunities in the gas industry in Ghana.

There is a difference in cost between the production of upstream associated and non-associated gas, and the total cost of gas-to-power integrated system depends on the price of gas, which is the primary influencing factor (Zhu et al., 2016). Natural gas prices are the most important parameter for providing financial analysis (Razavi, 2007). Besides gas prices, there are some other important factors that affect the cost of gas-to-power system. These include the price of electricity, capital and operating cost, operational methods, annual utilisation hours, sources of funds for construction, alternative cost of fuels, transmission tariffs and other factors (Zhul et al., 2016).

6.3.1. Component 1: Static Analysis of Upstream Gas Production

The Sankofa Gas Project is a Production Sharing Contract between GNPC, ENI-Ghana and Vitol Plc to produce associated and non-associated gas from two gas fields. The estimated total recoverable gas reserves from these fields are 1TCF [Upstream-GNPC]. Initial upstream Investments are meant to commercialise gas production in Ghana for electricity generation. The SGP cost components are captured in the extract on Table 31.

Table 31: Upstream Production of Gas Static Analysis

Component One: SGP	**Total Cost**	**Total Revenues**	**Fiscal Charge (Royalties)**	**Project NPV**
SGP	US$7.9billion	US$10.5billion	US$793.8m	US$673.3million
PSC Terms for Gas Revenues	**Share (%)**	**Discounted Returns (US$ m)**	**Discount Rate**	**10%**
			Income Tax	**35%**
ENI Ghana	44%	298,989,133.06	**ENI**	104,646,196.57
Vitol	36%	239,730,025.61	**Vitol**	83,905,508.96
GNPC	20%	134,679,789.67	**Total**	188,551,705.54
Total	100%	673,398,948.34		

Source: Based on Integrated Cash Flow Model Using @RISK v7.5.

The SGP static analysis from the integrated cash flow analysis in Appendix 3 has a project cost of US$7.9billion, which generates a revenue of US$10.5billion. The SGP attracted a fiscal charge of US$793.8million in gas royalties and income tax of (35%) US$188.5million to the Ghana government. SGP earned an NPV of US$673.3million. The share of project partners include ENI-Ghana (44%) US$298.9million, Vitol (36%) US$239.7million and GNPC (20%) US$134million. The SGP is a viable business and should be accepted. However, upstream deep-water projects require high capital costs considered very expensive and risky (Wright and Gallun, 2008). As a result, non-associated gas production is considered risky for investments in Ghana.

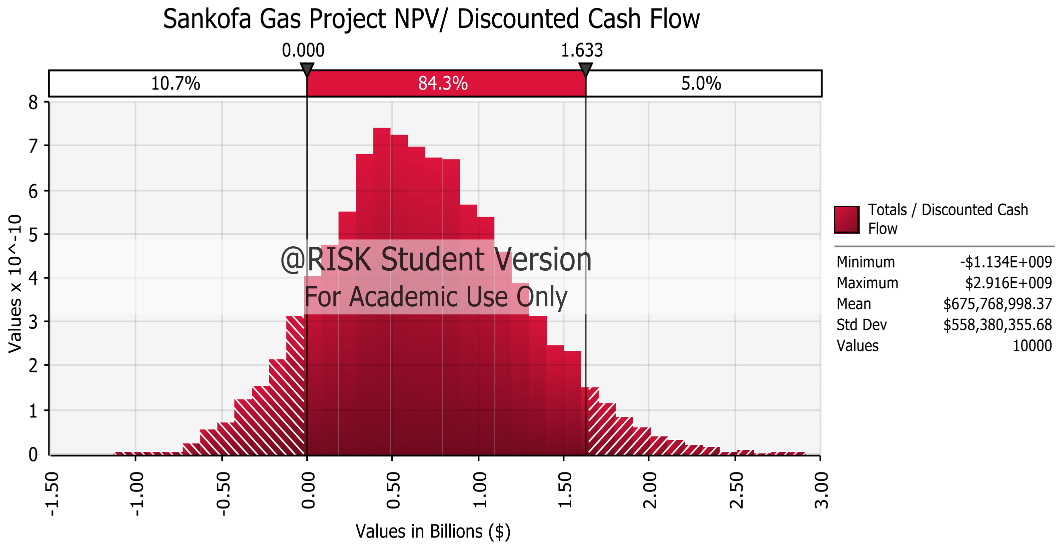
6.3.2. Simulation Analysis for the Gas Industry in Ghana

The static analysis above assumed that all the variables are constant over the 20years projects duration and generate all the revenues and NPVs, making the project a viable business. The gas industry operates in a dynamic global and local energy industry with changing conditions, which may alter the viability of the proceeding projects. Probabilistic analysis through simulations are performed considering several iterations of the changing dynamics in the gas industry. A normal distribution graph is selected for the probabilistic distribution from the @RISK software.

6.3.3. Component 1: Upstream Gas Production Simulation Analysis

The SGP simulation analysis includes the following input variables: gas production volumes of an average of 54BCF per annum, upstream gas price of US$9.8/MMBtu, discount rate of 10% and a royalty rate of 7.5% as indicated on the integrated cash flow model (see Appendix 3). The @RISK software generates a normal distribution simulation graph for upstream gas production as indicated on Figure 16.

Figure 16: Simulation Graph for Upstream Gas Production



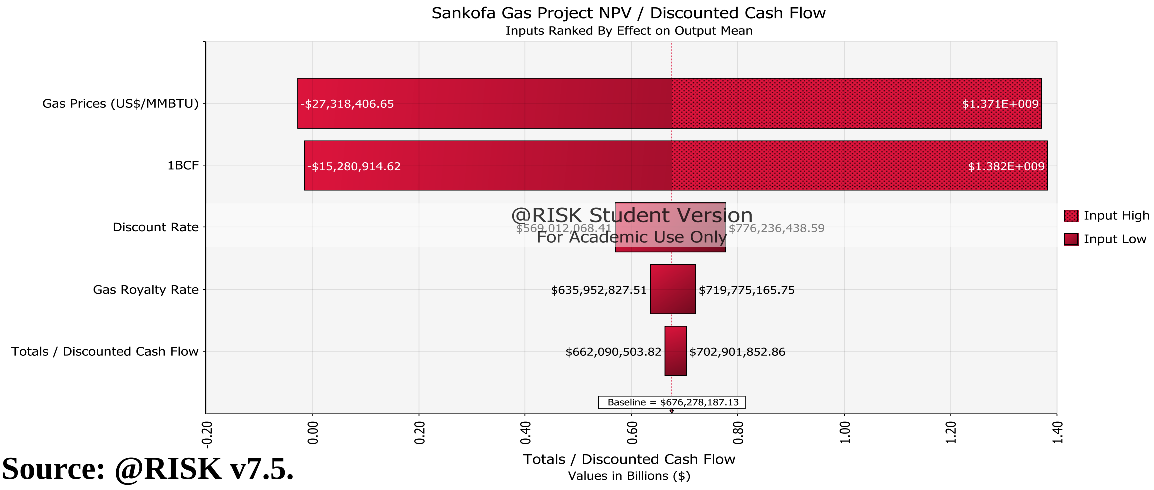
Source: Based on @RISK v7.5.

As indicated on the normal distribution simulation graph Figure 16, the NPV for SGP is US$673million with a 84.3% probability of the project breaking even and generating positive NPVs above the US$673million. There is a 10.7% probability of the project NPV going below the breakeven point and generating negative NPVs. The simulation graph shows that SGP has a higher probabilty of being a viable business and should be accepted with a 10.7% risk exposure.

6.3.4. Component 1: Upstream Gas Production Sensitivity Analysis

Sensitivity analysis relates the impact of the various identified risk factors to the projects' NPVs and show how they affect the viability of the projects. The risk factors affecting the business viability of the SGP include all the input variables (see Appendix 3). From Figure 17, gas prices, discount rate and royalty rates are identified as the most sensitive risk factors affecting the viability of the Sankofa Gas Project.

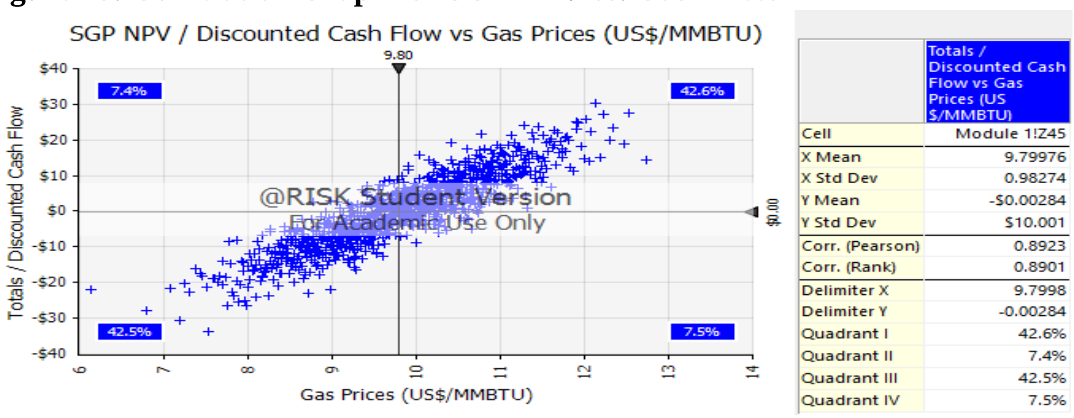
Figure 17: Sensitivity Graph for Upstream Gas Production



Source: @RISK v7.5.

Non-Associated Gas Prices: There is a positive correlation between the project NPV and upstream non-associated gas prices. The profitability of the SGP depends on non-associated gas prices (EIA, 2016) since the US$9.8/MMBtu upstream price is considered high. The higher non-associated gas prices, the higher the project NPV and vice versa as indicated on Figure 18.

Figure 18: Correlation Graph for SGP NPV vs. Gas Prices



Source: @RISK v7.5.

For example, a 10% reduction of upstream wellhead gas prices from US$9.8/MMBtu to US$8.82/MMBtu will lead to a reduction in the SGP NPV from US$673million to US$282.7million, which will still keep the SGP a viable business as indicated on Table 32. However, a further reduction in gas prices to below US$8.2/MMBtu, which is the breakeven point, will result to the non-viability of the project.

Table 32: Non-Associated Gas Prices Vs. Upstream SGP NPV (US$)

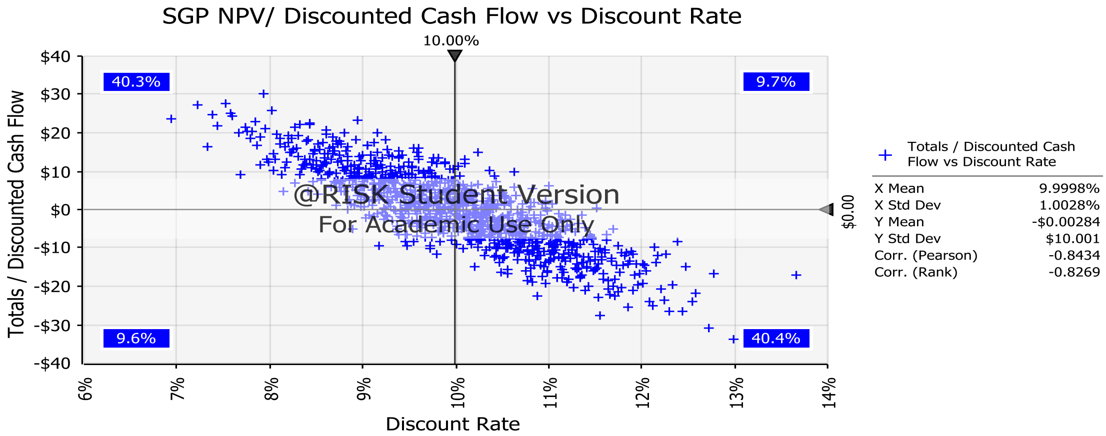
Natural Gas Prices (mmbtu)	% of change	NPV US$(m)
9.8	Current price	673.3
8.82	10%	282.7
8.2	Break-even Price	0

Source: Based on Integrated Cash Flow Model using @RISK.

For the viability of the SGP, a wellhead gas price of US$8.2MMBtu is the lowest possible price the SGP requires to break-even, any price below the breakeven point will result in the non-viability of the project. This implies that the SGP is very risky, and non-associated gas prices must be maintained at least above US$8.2/MMBtu for the SGP to remain a viable business.

Discount Rate: the policy rate from the Bank of Ghana is 20% (Bank of Ghana; 12/02/2018); however, this is not what is used for the SGP because the finances of the SGP are not generated internally. The IOCs are generating funds from the international capital market so a different discount rate is applied to the SGP, which is assumed to be equivalent to the World Bank rate of 10%. Discount rates are negatively correlated to the SGP NPVs as indicated on Figure 19. The lower the discount rate, the higher SGP NPVs and vice versa.

Figure 19: Correlation Graph for SGP NPV vs. Discount rate



Source: @RISK v7.5.

For instance, if the discount rate increases to 22%, the project NPV decreases to US$200million and if the discount rate decreases downward to 5%, the project NPV increases to US$1billion as indicated on Table 33. However, at a discount rate of 37%, the SGP breaks even. All things being equal, the SGP needs lower discount rates to remain viable.

Table 33: Discount Rate Vs. Upstream Gas Only Production NPV US$

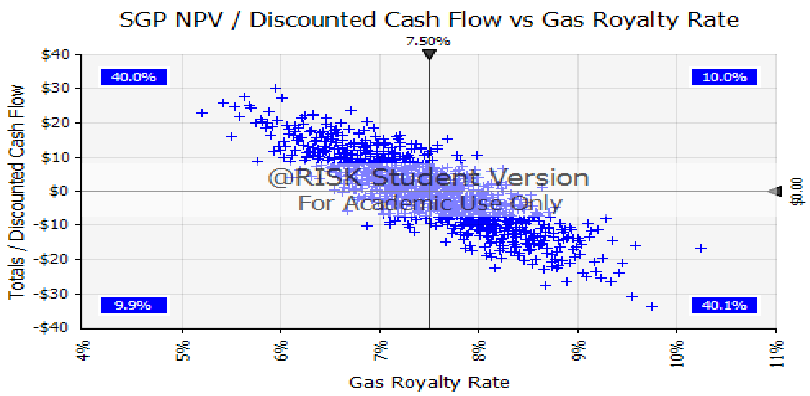
Discount Rate	**%Change in Discount rate**	**NPV US$ (m)**
SGP Rate	10%	673
Policy Rate in Ghana	22%	200
	20%	249
	15%	413
	5%	1000
Breakeven Point	37%	0

Source: Based on Integrated Cash Flow Model using @RISK.

Ensuring lower discount rates for gas projects in Ghana will require facilitating lower investment risks in oil and gas exploration activities and promoting guaranteed returns on investments through appropriate structural and regulatory frameworks.

Royalty Rate: the Model Petroleum Agreement (MPA) for Ghana has 7.5% royalty rate for gas production compared to 12.5% for crude oil production as incentives to enhance the viability of domestic gas projects in Ghana [Upstream-GNPC]. The royalty rate is negatively correlated to the SGP NPV. Increasing royalty rates indicate a decreasing project NPV and vice versa as indicated on Figure 20.

Figure 20: Correlation Graph for SGP NPV vs. Gas Royalty Rate



	Totals / Discounted Cash Flow vs Gas Royalty Rate
Cell	Module 1!Z45
X Mean	7.49982%
X Std Dev	0.75209%
Y Mean	-$0.00284
Y Std Dev	$10.001
Corr. (Pearson)	-0.8332
Corr. (Rank)	-0.8157
Delimiter X	0.074998
Delimiter Y	-0.00284
Quadrant I	10.0%
Quadrant II	40.0%
Quadrant III	9.9%
Quadrant IV	40.1%

Source: @RISK v7.5.

For instance, a decrease in royalty rates from 7.5% to 5% will result in an increase in the SGP NPV from US$673million to US$778million. Royalty rates at 24% is the break-even rate and above 24% will lead to the non-viability of the SGP, whilst a 7.5% and a decrease to 5% royalty rate increases the project viability to US$778million as indicated on Table 34. That is, SGP needs lower royalty rates to remain viable.

A reduction in the royalty rate or elimination of the royalty rate on gas production as a government of Ghana fiscal policy will increase the business viability of non-associated gas production in Ghana. If the royalty rate is eliminated/reduced to zero, the SGP non-associated gas prices can be reduced from US$9.8/MMBtu to US$7.6/MMBtu and the SGP will still remain viable at a positive NPV of US$42million.

Table 34: Royalty Rate Vs. Upstream SGP NPV US$

Gas Royalty Rate	%Change	NPV US$ (million)
Current Rate	7.50%	673
	6.50%	715
	5%	778
	20%	145
Break-even Point	24%	0

Source: Based on Integrated Cash Flow Model using @RISK.

Consideration can be given to gas production royalties meant for domestic consumption to promote further upstream investments in gas production to reduce investment risk and reduce the downstream cost of natural gas in Ghana. Royalty rates can be reviewed, reduced or eliminated aimed at ensuring the viability of the SGP.

6.4.0. Component 2: Gas Processing Plant (GNGC)

The gas that is produced upstream is different from the gas that is consumed by the thermal plants (Younger, 2004). The gas must be processed into methane and made available to a transmission pipeline to be delivered to the CCGT. GNPC is the upstream gas aggregator, which delivers gas to the GPP under the SBM of which Ghana National Gas Company (GNGC) as a subsidiary of GNPC operates the GPP.

GNPC aggregates upstream gas from the SGP at a price of US$9.8/MMBtu to be delivered to the GPP operated by GNGC. The GPP is required to process both associated and non-associated gas, separated into pure methane/lean gas as feedstock for the CCGT and LPG for household consumption. GNPC is considered as the gas owner according to the three interviews [Upstream-GNPC; Midstream-GNGC; Min-Energy] responsible for the cost of delivering upstream gas to downstream consumers. It is assumed that 97% of the gas received from upstream (54BCF/annum on average) is processed into methane/lean gas while 3% is processed into other products (ethane, propane and butane) sold as Liquefied Petroleum Gas (LPG). The Table 35 indicates the static analysis of the GPP.

Table 35: Gas Processing Plant Static Analysis

Component 2: Gas Processing Plant	**Total Cost (US$m)**	**Total Revenues (US$)**	**Discount Rates**	**NPV (US$m)**
Methane (97%) and LPG (3%)	733million	2.9billion	10%	566million
Upstream gas cost	US$9.8/mmbtu			
Processing Tariff	US$3/mmbtu			
Products Selling Price	US$320/mt			
Products Volumes	3% of upstream gas			
Methane Gas Volumes	97% of upstream gas			

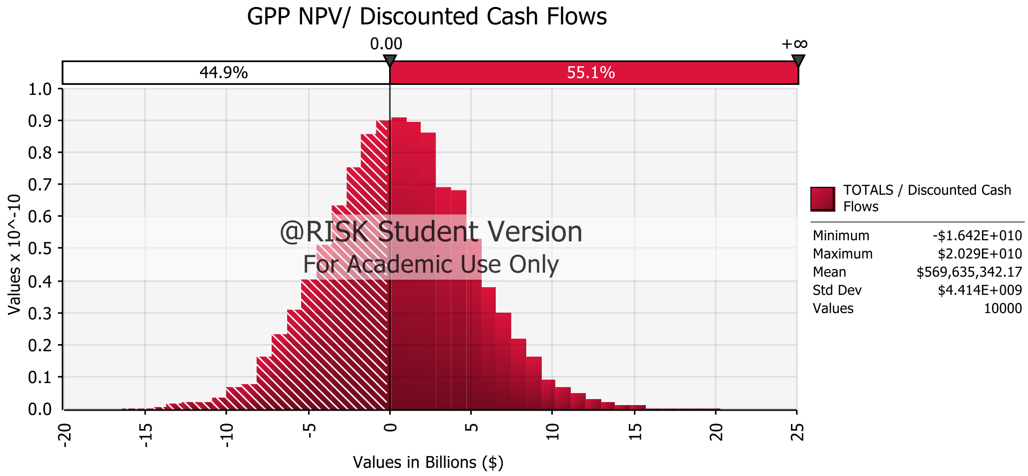
Source: Based on Integrated Cash Flow Model using @RISK.

GNGC invested US$733million of total cost on the GPP, which generated revenues of US$2.9billion. The GPP generated a positive NPV of US$566million at a 10% discount rate, which indicates that over the 20years duration, the GPP is a viable business, which significantly depends on the prices of products (LPG), sold at US$320/mt. The viability of the GPP significantly depends on LPG sale prices.

6.4.1. Component 2: Simulation Analysis of the GPP

The GPP is assumed to be operating as a separate business entity and receives natural gas from Component 1: SGP. The input variables include gas volumes from upstream of an average of 54BCF/annum, upstream gas prices of US$9.8/MMBtu, gas-processing tariff of US$3/MMBtu and products (LPG) selling price of US$320/mt as contained in the Excel Sheet (Appendix 3).

Figure 21: Simulation Graph for the Natural Gas Processing Plant



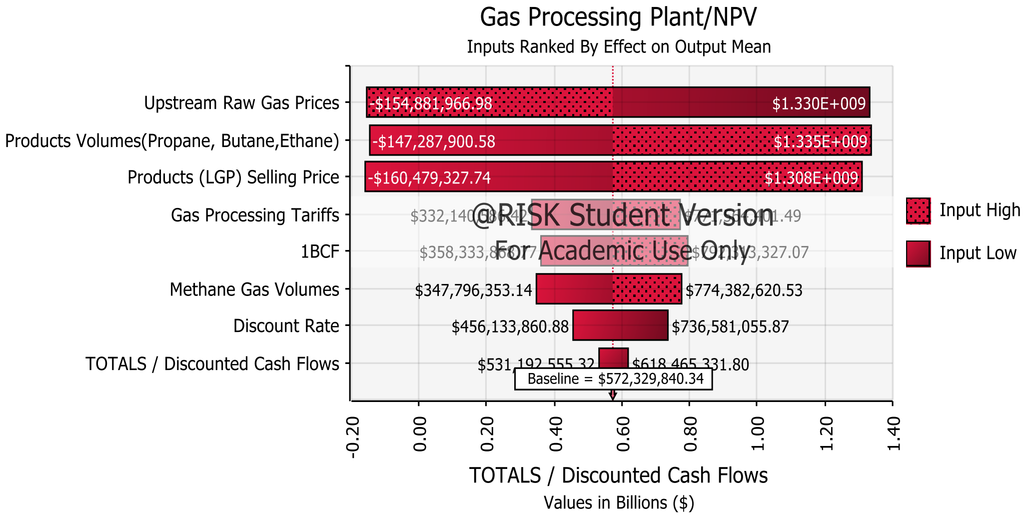
Source: @RISK v7.5.

The normal distribution graph of the GPP on Figure 21 generated US$566million in NPVs and indicates a 44.9% probability of generating negative NPVs and 55.1% of generating positive NPVs. The GPP is, therefore, a viable business from both the static and simulation analysis. However the GPP has a 44.9% risk exposure which affects its viability.

6.4.2. Component 2: The GPP Sensitivity Analysis

What risk factors affect the viability of the GPP? Upstream raw gas prices, products (Liquefied Petroleum Gas) prices, volumetric risk (products volumes and methane gas volumes), gas processing tariffs and discount rates as indicated on Figure 22 are the risk factors affecting the viability of the GPP.

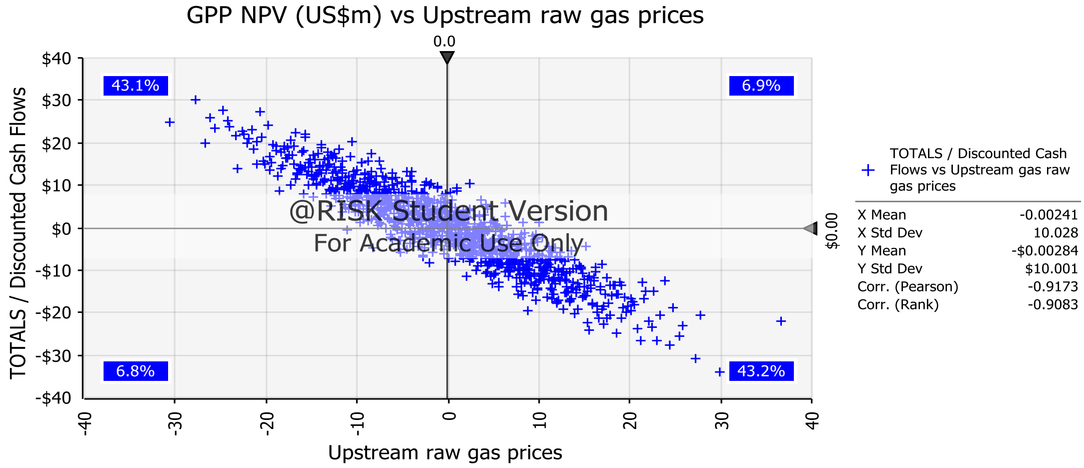
Figure 22: Sensitivity Graph for the GPP



Source: @RISK v7.5.

Upstream natural gas prices: the GPP depends on the upstream production of gas so the viability of the GPP depends on upstream gas prices. Upstream price of raw gas is identified as the most sensitive risk factor affecting the viability of the GPP as indicated on the sensitivity graph Figure 22.

Figure 23: Correlation Graph for GPP NPV vs. upstream raw gas prices



Source: @RISK v7.5.

There is a negative correlation between the GPP NPV and upstream raw gas prices as indicated on the correlation graph Figure 23. Higher raw gas prices negatively affect the viability of the GPP. For instance, a 10% increase in raw gas prices from US$9.8/MMBtu to US$10.78/MMBtu will result in the reduction of the GPP NPV from US$566million to US$144.5million. Upstream raw gas price of US$11.10/MMBtu is the break-even point for the GPP viability. At prices above US$11.10/MMBtu, the GPP records negative NPVs and becomes non-viable as indicated on Table 36.

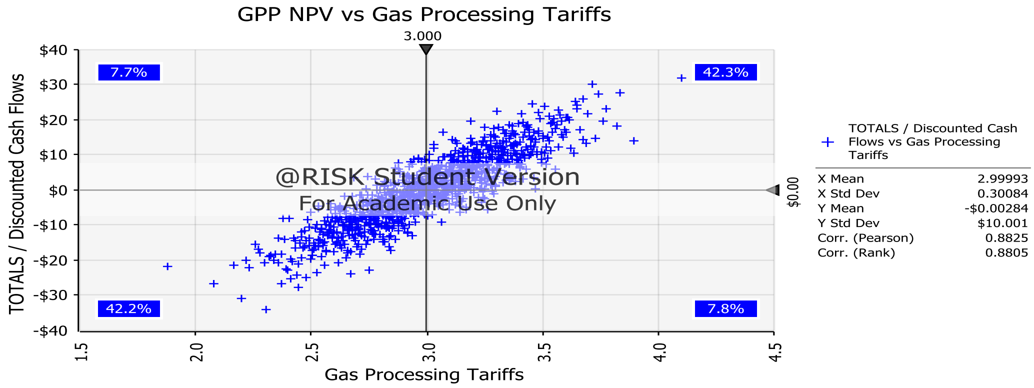
Table 36: GPP NPV vs. Upstream Raw Gas Prices

Upstream Raw Gas Pries	% Change	GPP NPV (US$m)
9.80	Current price	566.80
10.78	10%	144.50
11.10	Break-even	0

Source: Based on Integrated Cash Flow Model using @RISK.

Natural Gas Processing Tariff: these are not very sensitive to the profitability of the GPP compared to upstream raw gas prices. Even though pure methane is the main reason for building the GPP, its processing tariffs are not very sensitive to the GPP viability. A lean gas-processing tariff of US$3/MMBtu is charged. There is positive correlation between gas processing tariffs and GPP NPV as indicated on Figure 24. Increasing processing tariffs result in higher GPP NPV while lower tariffs lead to lower NPV.

Figure 24: Correlation Graph for GPP NPV vs. Gas Processing Tariffs



Source: @RISK v7.5.

For instance, a 50% reduction in the GPP processing tariff from US$3/MMBtu to US$1.7/MMBtu keeps the GPP a viable business but reduces NPV drastically from US$566million to US$23million as indicated on Table 37. However, reducing methane gas processing tariffs lowers domestic downstream final gas tariffs, which positively affects the viability of the CCGT. The question then is "why not reduce methane gas processing tariffs?"

Table 37: Natural Gas Processing Tariff vs. GPP NPV (US$)

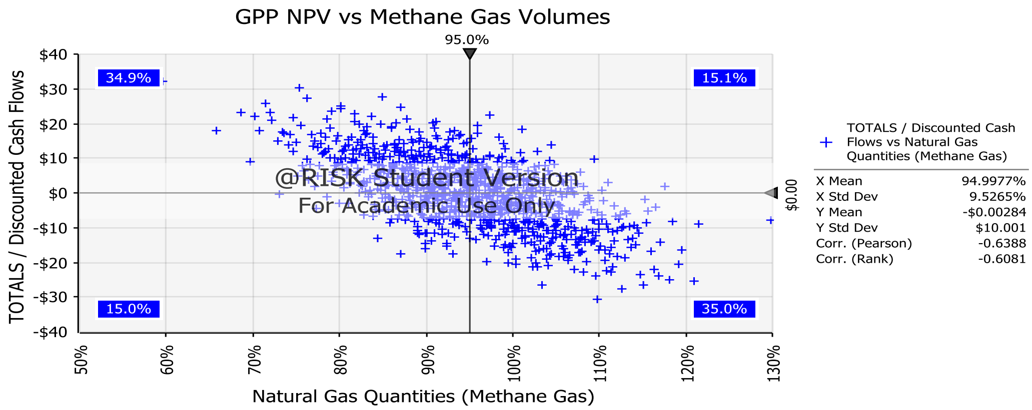
Natural Gas Processing Tariff US$/mmbtu	Decreasing	NPV US$ (million)
3		566
2.7	10%	441
2.1	30%	190.8
1.7	50%	23
Break-even Price	1.5	0

Source: Based on Integrated Cash Flow Model using @RISK.

The GPP break-even tariff is US$1.5/MMBtu. Any reduction in tariff to below US$1.5/MMBtu will result in the non-viability of the GPP; this is the lowest tariff the GPP can charge. The GPP viability is dependent on charging fair tariffs for processing lean gas. The activities of the GPP should, therefore, be regulated by PURC, especially concerning lean gas processing tariffs. This is because even at a GPP tariff of US$1.7/MMBtu, the project still generates positive NPVs. This indicates that the current US$3/MMBtu GPP tariff is high and inappropriately set.

Production Volumes: volumetric risk is considered a major risk factor to the viability of the GPP. The ratio of methane/LPG productions is dependent on the content of the associated gas from the SGP. The more condensates volumes there are, the higher the LPG content and vice versa.

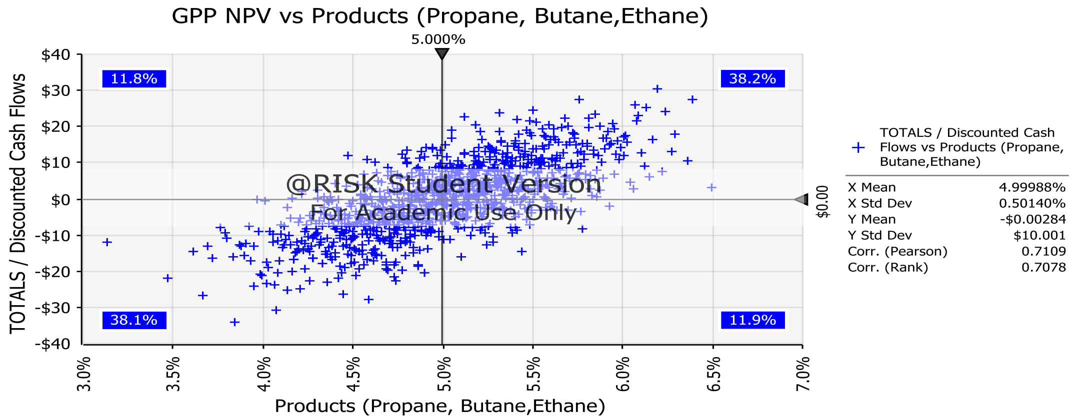
Figure 25: Correlation Graph for GPP NPV vs. Methane Gas Volumes



Source: @RISK v7.5.

The higher pure methane gas production volumes from upstream to the GPP, the lower the viability of the GPP. From the Figure 25, Methane gas-processing volumes lowers the production of associated gas products (LPG). Methane gas processing volumes are negatively correlated to the viability of the GPP. From Figure 26, the viability of the GPP is highly dependent on the processing of products (LPG). The product sale values provides significant revenues for the GPP. The higher the products (LPG) processing volumes, the higher the viability of the GPP. Products (LPG) volumes are positively correlated to the viability of the GPP. Products volumes (LPG) are the most significant component of the GPP viability.

Figure 26: Correlation Graph for GPP NPV vs. Products (LPG)



Source: @RISK v7.5.

For instance, a slight reduction in product (ethane, butane and propane) volumes from 3% to 2% whilst pure methane volumes increase to 98% from 97% sees the GPP recording negative NPVs. The GPP will not be viable without significant products (LPG) volumes as indicated on Table 38. LPG has higher market value in Ghana at US$320/mt; it is a source of fuel for household cooking and vehicles (Suleman et al, 2017).

Table 38: Lean Gas and LPG Quantities Ratios vs. GPP NPV (US$)

Methane Gas Volumes (%)	Products (LPG) Volumes (%)	NPV US$ million
97%	3%	566
98%	2%	0

Source: Based on Integrated Cash Flow Model using @RISK.

Should the GPP operate under the SBM or as a separate entity under the MBM? The more associated gas the GPP processes, the higher the GPP NPV. The GPP is an essential facility, which is running below full capacity of

150,000MMBtu/d [Midstream-GNGC] and currently processes marginal volumes. Additional volumes from other gas fields will see full optimisation of the GPP. The GPP should be allowed to operate on open access and non-discriminatory third party basis even if GNPC remains the upstream aggregator for the current production fields (Jubilee, TEN and SGP).

This will mean that several sources of natural gas would be made available to the GPP from other production fields to enable the GPP operate at the 150,000MMBtu full capacity. When the GPP exceeds full capacity, expansion and new GPPs could be considered. Other risk factors that may affect the viability of the GPP include force majeure, regulatory risk, credit risk, liquidity risk and many more.

6.5.0. Component 3: The Natural Gas Pipeline: the case of BOST

The integrated cash flow model treats the transmission pipeline as a separate business entity operated by the selected NGTU (BOST) and as another cost unit to final gas prices charging a transmission tariff of US$2.28/MMBtu [Midstream-GNGC]. This is separated from the GPP and are not considered as a bundled service. The transmission pipeline operates as a pipeline service company offering transportation services in extra available pipeline capacity to multiple users. The Transmission Pipeline is connected to the GPP to transport methane/lean gas to consumers (CCGTs at the West). The current capacity of the pipeline is 150,000MMBtu/d with the potential of being increased to 440,000MMBtu/d [Midstream-GNGC].

Table 39: Transmission Pipeline Static Analysis

Component 3: BOST Pipeline	Total Project Cost US$ (Million)	Total Revenues US$	Discount rate	NPV US$ (million)
BOST Pipeline	537.7	2.26billion	10%	552.9
Transmission Tariffs	US$2.28/mmbtu			
Estimated Transmission losses	5%			

Source: Based on Integrated Cash Flow Model using @RISK.

The transmission pipeline generates US$2.26billion in revenues at a transmission tariff of US$2.28/MMBtu transmitting, on average, 54BCF/annum of gas over a 20-year period. Five percent (5%) of the gas received from the GPP is lost to heating and leakages leaving 95% to be finally delivered to the CCGT. The transmission pipeline operators invested US$537.7million and generated positive NPVs of US$552.6million at a 10% discount rate indicating business viability which is 100% return on investments whilst upstream gas producers are getting less than 10% return on investments as discussed above. The transmission pipeline business, thus, indicates very high business viability.

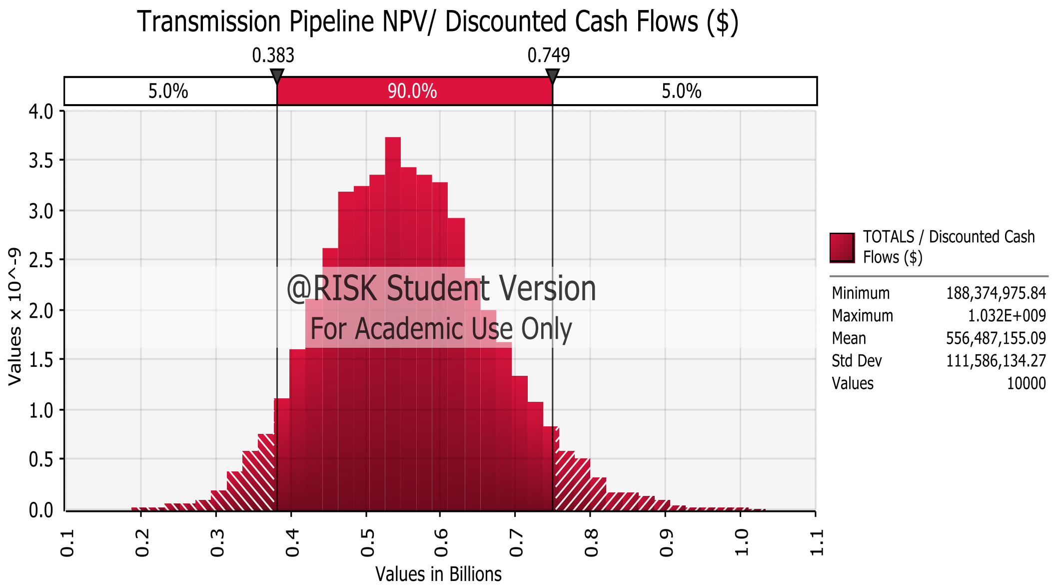
Operating the pipeline in the SBM will mean GNPC has monopoly power on the transmission pipeline and that only GNPC's gas will have priority access to the pipeline. In an MBM, multiple gas owners will require access to the pipeline. This will require that the pipeline operate on an open access and non-discriminatory basis. Even though the pipeline can operate on an open access system under the SBM, non-discriminatory access cannot be guaranteed.

Essentially, the pipeline is exposed to volumetric risk similar to the GPP. The current capacity of the pipeline is 150,000MMBtu but can be optimised to full capacity of 442,000MMBtu/d with additional compressors. Multiple gas sources under the MBM will mean that the pipeline will have additional revenues with extra capacity to transmit other users' gas. Adding another user to the pipeline will require capacity management as to whose gas should be sent first, and this will mean operating the pipeline as an unbundled structure through a regulated open access regime.

6.5.1. Component 3: Transmission Pipeline Simulation Analysis

The transmission pipeline receives processed gas from the SGP through the GPP. The input variables for the transmission pipeline's normal distribution graph simulation analysis include transmission tariffs of US$2.28/MMBtu, discount rate of 10% and the estimated loss rate of 5% as captured on the Excel Spreadsheet Appendix 3.

Figure 27: Simulation Graph for the BOST Transmission Pipeline



Source: @RISK v7.5.

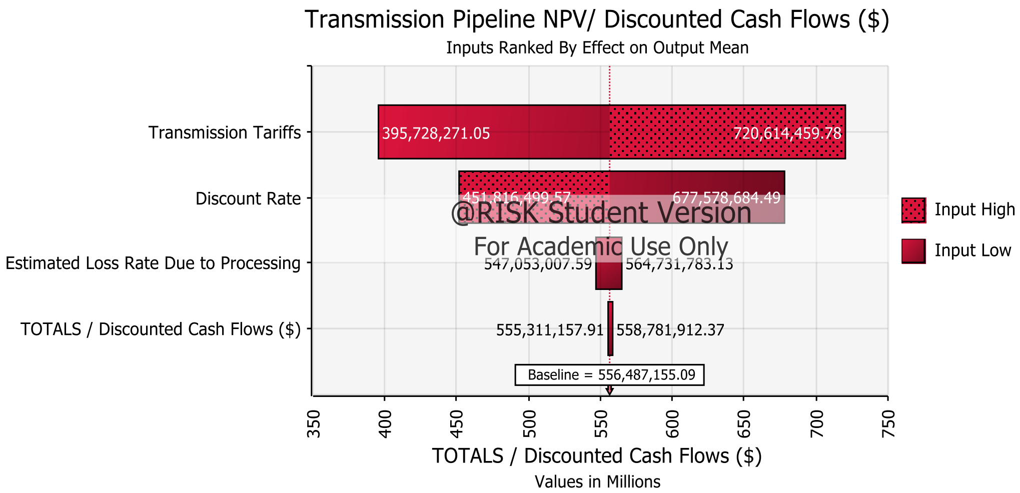
The transmission pipeline indicates a 90% probability of generating positive NPVs within the range of US$383million and US$749million. The transmission pipeline displayed limited risk exposure on the normal distribution simulation graph. The risk factors identified as affecting the viability of the transmission pipeline are volumetric and transmission tariff risks.

Operating the transmission pipeline under third party access and unbundling the gas transmission pipeline from GNPC to operate as a separate business entity [Midstream-EC] will ensure adequate multiple user access and may increase gas transmission volumes which will generate extra cash flow from the other users.

6.5.2. Component 3: Transmission Pipeline Sensitivity Analysis

According to an interviewee [Midstream-GNGC], a combined charge of US$5.28/MMBtu is required for the GPP processing and transmission of gas tariff under the SBM. The GPP tariff of US$3/MMBtu is charged for gas processing and US$2.28/MMBtu for the transmission tariff. From the sensitivity graph Figure 28, transmission tariffs, discount rate and estimated loss rate are the most sensitive risk factors assuming a constant gas flow of 54BCF/annum.

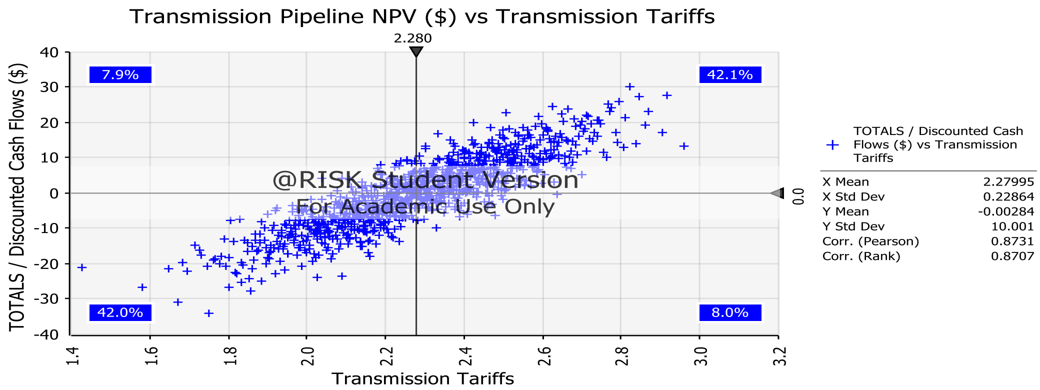
Figure 28: Sensitivity Graph for the Transmission Pipeline NPV (US$)



Source: @RISK v7.5.

Transmission Tariffs: increasing transmission tariffs indicates higher NPVs and decreasing transmission tariffs results to lower NPVs. There is a positive correlation between transmission tariffs and the transmission pipeline NPVs as indicated on Figure 29.

Figure 29: Correlation Graph for the Pipeline NPV vs. Tariffs



Source: @RISK v7.5.

For instance, a 50% reduction in transmission tariffs from US$2.28/MMBtu to US$1.14/MMBtu maintains the pipeline NPV as a viable business as indicated on Table 40. By this, the current transmission tariffs can be reduced further by 50% and the pipeline will remain viable. The lowest possible tariff the pipeline can charge is US$0.9/MMBtu and this is the break-even tariff, as any tariff below this will result in negative NPVs. Why then are transmission tariffs so high in Ghana? This, as well, indicates that transmission tariffs are inappropriately set and require regulations.

Table 40: Scenario One: Transmission Tariffs Vs. Pipeline NPV (US$)

Transmission Tariffs US$/MMBtu	Decreasing %	NPV US$ million
2.28		552.9
2.05	10%	461.6
1.6	30%	282.8
1.14	50%	100.2
0.9	Break-even Point	0

Source: Based on Integrated Cash Flow Model using @RISK.

Volumetric risk is identified as the major risk factor affecting the viability of the transmission pipeline. Rate-of-return and incentive or performance based regulatory systems can be combined to regulate the pipeline capital cost recovery since pipelines usually have lower operation costs with multiple users. Additional volumes will need to be added and transported to optimise the current underutilised pipeline capacity of 150,000MMBtu/d. Compressors could also be used to increase the existing capacity to 440,000MMBtu/d to fully utilise the pipeline capacity. This may result in lower average cost and lower transmission pipeline tariffs as well as lower downstream gas prices (Eberhard, 2007).

6.6.0. Component 4: Combined Cycle Gas Thermal Plant (CCGT): TICO

To utilise the natural gas from the SGP for power generation, a 1100MW combined cycle gas thermal power plant is required. Either this can be a single plant or four smaller thermal plants summing to 1100MW of 275MW, each connected to the integrated gas system of which TICO-IPP is assumed to be the operator and downstream receiver.

6.6.1. Component 4: CCGT Power Plant Static Analysis

The integrated cash flow framework has the CCGT power plant as the final point of the gas industry value chain. The SGP gas is delivered to the GPP to be processed and condensed. The transmission pipeline then receives this gas, which is transmitted to the TICO-IPP CCGT plant located at Takoradi-Aboadzi thermal power plant enclave (Western Region of Ghana). Table 41 discusses the major features of the CCGT power plant.

Table 41: CCGT Thermal Plant Details

Plant Capacity (MW)	1100
Capital Cost	950$/kW
Plant Cost US$ million	1045
Plant Life	20years
Plant Load Factor	90%
Plant Efficiency	48%
Heat Rate	7120BTU/kWh

Source: World Bank (2013).

The CCGT is assumed to have a construction cost of US$1.045billion and a plant load factor of 90% with an efficiency rate of 48% (World Bank

2013). It is to operate for 325days with 40days for downtimes, repairs and maintenance in a year for 20years. Gas or LCO are the main fuels for the plant and a wholesale electricity tariff of US$0.09cent/KWh is charged for electricity sold to VRA, the wholesale bulk electricity buyer in Ghana.

Table 42: Combined Cycle Gas Thermal Power Plant Static Analysis

Component 4: CCGT Power Plant	**Total Capital Cost US$**	**Total Revenues US$**	**Discount Rate**	**NPVUS$**
TICO CCGT	10.3billion	12.6billion	10%	388.4million
Gas Required	49.95BCF			
Gas Prices	US$8.7/mmbtu			
Wholesale electricity tariff	US$0.09/kWh			

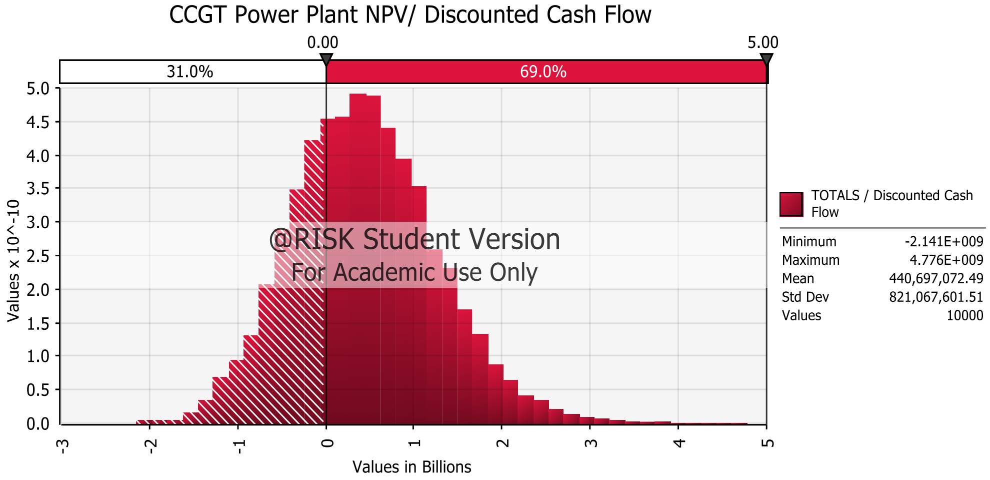
Source: Based on Integrated Cash Flow Model using @RISK.

The total capital cost of the CCGT is US$10.3billion, generating revenues of US$12.6billion discounted at 10% to generate a positive NPV of US$388.4million. This shows the business viability of the CCGT plant. The CCGT plant will take gas from the transmission pipeline at prevailing downstream domestic gas prices averaged at US$8.7/MMBtu to produce electricity which is to be sold at current electricity wholesale market prices of US$0.09kWh for the project duration of 20years [Downstream-VRA].

6.6.2. Component 4: CCGT Simulation Analysis

Electricity generation has the highest netback value for the SGP. The input variables for the simulation analysis are annual electricity generation capacity, gas prices (US$8.7/MMBtu), electricity tariffs (US$cent 0.09/kWh), heat rate (7120BTU/kWh), plant efficiency (48%) and load factor (90%) (World Bank, 2013) as indicated on the Excel Spreadsheet Appendix 3.

Figure 30: Simulation Graph for the CCGT Plant



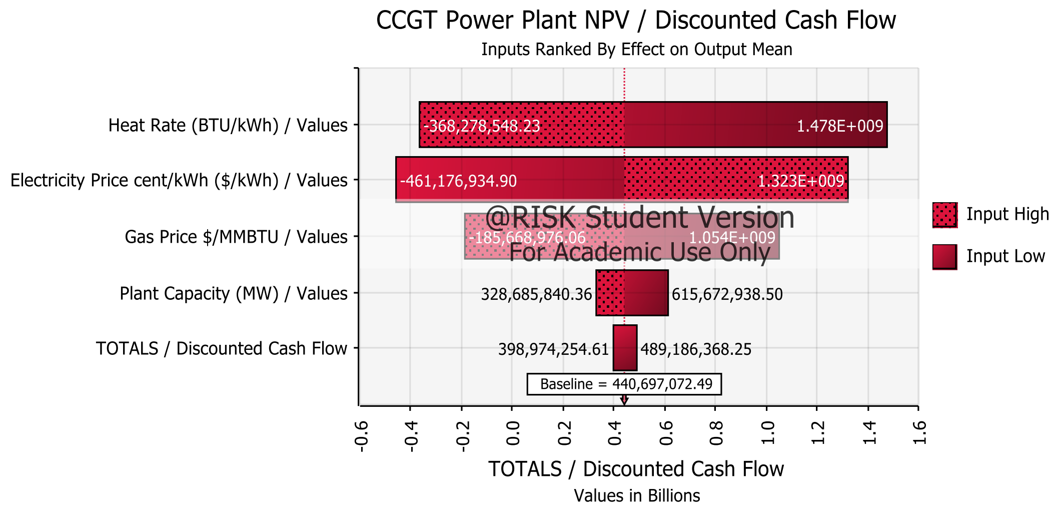
Source: @RISK v7.5.

The CCGT, generated a positive NPV of US$388.4million and shows a 69% probability of generating positive NPVs and a 31% probability of generating negative NPVs below the breakeven point (0). The CCGT is considered a viable business; however, with a higher risk exposure of 31% probability of generating negative NPVs.

6.6.3. Component 4: CCGT Sensitivity Analysis

How sensitive are the various identified risk factors affecting the viability of the TICO CCGT plant? Heat rate, electricity prices, gas prices and plant capacity are identified as the most sensitive risk factors affecting the viability of the CCGT power plant. Electricity and gas prices are the risk factors in the remit of the gas industry in Ghana. The other factors, such as heat rate, plant efficiency and plant load factor are considered technical risk factors.

Figure 31: Sensitivity Graph for the Transmission Pipeline NPV (US$)

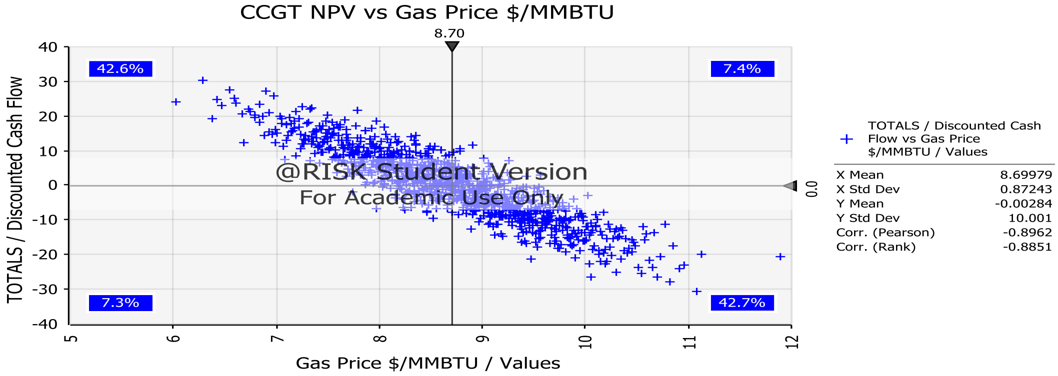


Source: @RISK v7.5.

Gas Prices: there are two price components of domestically produced natural gas in Ghana: the commodity price, which is the cost of production on one hand and the cost of processing, transmitting and distributing to final consumers on the other hand (EIA, 2017). In essence, GNPC aggregates upstream gas and provides an average downstream final gas price taking into consideration the commodity price differentials and adding the processing and transmission tariffs as well as regulatory levies and taxes.

Domestically produced gas is priced at US$8.7/MMBtu to the thermal power plant. This includes the upstream associated gas prices and non-associated gas prices from three different production fields with different prices. These prices are aggregated to provide an average price of US$8.7/MMBtu to thermal plants. However, there is a negative correlation between the CCGT power plant and gas prices. The higher the gas price, the lower the CCGT NPVs and business viability and vice versa. This is depicted on Figure 32.

Figure 32: Correlation Graph for the CCGT NPV vs. Gas Prices



Source: @RISK v7.5.

There are different gas prices available in Ghana. The price of LCO, which is a competing fuel for power generation, and the possibility of importing LNG to supplement domestic gas consumption are presented on Table 43. The integrated cash flow model will give a combined gas price of US$15.08/MMBtu, generating negative NPVs for the CCGT. The CCGT NPV is sensitive to fuel prices, and gas presents the cheapest fuel source.

Table 43: Natural Gas Prices to the CCGT vs. CCGT NPV (US$)

Gas Prices US$/MMBtu[36]		**NPV US$ million**
Domestically Produced Gas Average Price	8.7	388.4
WAGPCo	8.6	428
Break-even price	9.6	30
Levelised Gas Prices	6.6	1.2billion
LNG	10.5	-326
Imported Light Fuels	12	-922

Source: Based on Integrated Cash Flow Model using @RISK.

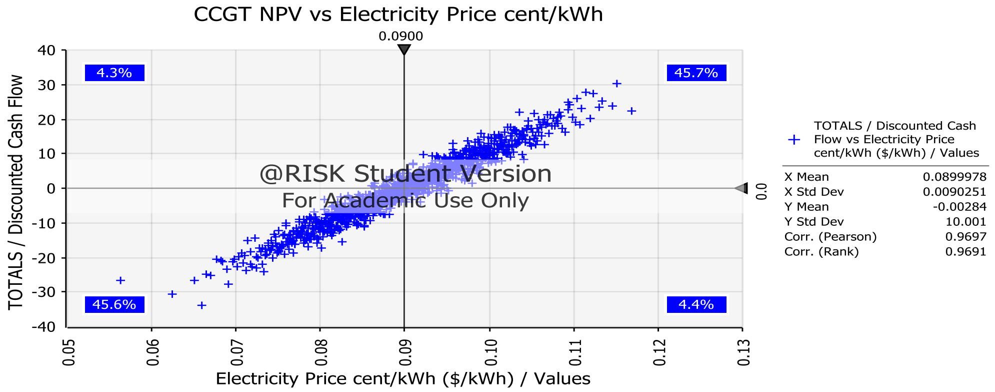
Domestic gas prices (US$8.7/MMBtu) and WAGP gas price (US$8.6/MMBtu) (Ministry of Energy Gas Master Plan, 2015) make the CCGT a viable business. The break-even gas price is US$9.6/MMBtu so any price

[36] Gas Prices are obtained from the Ministry of Energy (2015) Gas Master Plant for Ghana.

above this makes the CCGT non-viable. LNG and LCO equivalent prices are non-competitive alternative fuels for the CCGT compared to domestic and WAGP gas prices. The LNG from the FSRU and LCO will require higher wholesale electricity tariffs to be increased from US$0.09cent/kWh to US$0.2cent/kWh to remain viable. LNG can be sourced from very competitive markets with much lower prices.

Electricity Prices: Power generation in Ghana has shifted from hydropower to depend on very expensive fuels such as gas or LCO. The high domestic and WAGPCo gas prices means electricity tariffs must increase to support the cost of generation and investments required. There is a positive correlation between electricity prices and the viability of the CCGT. Regarding this, higher wholesale electricity tariffs indicates higher CCGT NPVs and vice versa as indicated on the correlation graph Figure 33.

Figure 33: Correlation Graph for the CCGT NPV vs. Electricity Prices



Source: @RISK v7.5.

The CCGT needs wholesale electricity tariffs above US$0.09cent/kWh to remain viable. For instance, electricity tariffs below US$0.09cent/kWh will result in the CCGT recording negative NPVs as indicated on Table 44 while a

10% reduction in electricity tariffs to US$ 0.081cents /kWh will lead to negative CCGT NPVs.

Table 44: Electricity Prices Vs. CCGT NPV (US$)

Electricity Prices US$ cents /kWh	%Change	NPV US$ million
0.09	-	388.4
0.081	10%	(-113.6)

Source: Based on Integrated Cash Flow Model using @RISK.

It is reported that wholesale electricity tariffs in Ghana are the highest in the West African Sub-region above the average price of US$0.04cent/kWh (African Centre for Energy Policy, 2017). Electricity tariffs set in Ghana at the current sub-regional average of US$0.04cent/kWh will see the CCGT record negative NPVs (of US$2billion), which is a drastic loss. Wholesale electricity generated from natural gas in Ghana cannot be sold at the possible lowest price of US$0.09cent/kWh as indicated in this study, and this accounts for the high cost of electricity in Ghana.

The gas produced at the SGP, if dedicated to power generation, can sustain 1100MW plant and this will be sufficient to significantly transform power supply dynamics and accelerate the much-needed economic growth in Ghana. However, this will required guaranteed economic gas and electricity tariffs. As indicated in Chapter Two (2.4.1. Challenges in the Electricity Sector in Ghana), to guarantee that the electricity sector is able to pay for the sustainability of the nascent gas industry there should be able to pay economic tariffs for electricity. The mining sector indicates higher ability and willingness to pay economic tariffs for secured and reliable electricity, which the SGP can offer 1100MW of power.

This will require downstream electricity consumption segregation in Ghana's electricity sector. Whereby high consumers who are willing and able to pay for economic tariffs such as the mining companies are separated from low consumers such as residential and public sector consumers who are unable and unwilling to pay economic tariffs on time especially at this point where cheap electricity cannot be guaranteed from existing thermal plants. These high consumers such as the mining companies can be segregated and tied into thermal plants power generation option to be guaranteed secured and reliable electricity at economic tariffs.

For the lower consumers, which require cheap power, are unable and unwilling to pay economic tariffs sees electricity as a public good[37] to be provided to all Ghanaians, requiring government subsidies to survive. Cheaper generation sources such as the hydrogenations from Akosombo, Kpong and Bui dams and renewable energy sources can serve such vulnerable consumers with limited constraints to the thermal generation sector.

In the long-term renewable energy from especially solar PVs in large and small scales can be offered as alternatives to low income consumers and as pro-poor government of Ghana energy subsidy program. Mini-solar PVs can be offered to the very low income and poor consumers especially to urban and rural

[37] Public good has the following characteristics; it is non-rival and non-excludable and is valued by individuals. Many of the 'classic' public goods involve massive infrastructure and prohibitive operational cost. Example; national high way system, energy systems or a television network.

poor consumers as Ghana government targeted subsidies program at relatively cheaper rates. The era of cheap electricity is getting to an end in Ghana and the industry can only survive when consumers are able and willing to pay economic tariffs for electricity. It is imperative to direct SGP gas to IPPs to generate electricity, which will be sold to mining companies to guarantee the sustainability of the SGP and the overall gas industry. Credible consumers who are able and willing to pay reliable and secured gas and electricity tariffs are important for the sustainability of the SGP (World Bank, 2015).

In a MBM: B industry structure, upstream gas investors will be able to transact gas trades directly with downstream consumers such as IPPs, which are able and willing to pay economic tariffs. IPPs can then serve as credible off-takers for gas supply contracts instead of GNPC or VRA. At the same time, IPPs can sell their electricity directly to these mining companies for guaranteed economic electricity tariffs to enable full cost recovery of the electricity and gas value chain. New gas and electricity transaction contracts such as upstream gas producers/suppliers-IPPs-Mining Companies instead of the highly contested existing state structure of GNPC-GNGC-VRA structures known for its hold-up and lock-in problems will emerge to avert the existing non-payments issues and inefficiencies. If these challenges are solved adequately IPP investments confidence will increase in power generation in Ghana.

6.7.0. Risk Factor Evaluations

In sum, the integrated cash flow analysis identified several risk factors as indicated on Table 45 affecting the viability of the supply components of the gas industry value chain and the various projects NPVs. The SGP is affected by the changing upstream gas prices, discount rates and royalty rates. The GPP, as well, is exposed to upstream gas prices, gas processing tariffs and volumetric risk. The transmission pipeline faces volumetric risk and lower transmission tariffs risk. Finally, the CCGT is affected by lower electricity tariffs and higher gas prices. To mitigate these identified risk factors on the nascent gas industry in Ghana is to improve regulations and promote competition however possible.

Table 45: Risk Factors Summary Table

Components	**Major Risk**	**Impact/ Correlation on NPV**	**Mitigation**
Upstream Gas Production: SGP	Gas Prices	Positive	Regulations
	Discount Rate	Negative	Competition
	Royalty Rate	Negative	Regulations
Natural Gas Processing Plant	Raw gas prices	Negative	Regulations & competition
	Products (LPG) selling Price	Positive	Competition
	Methane Gas Volumes	Negative	Regulation
	Gas Processing Tariffs	Positive	Regulations
Natural Gas Transmitting Pipeline	Transmission tariffs	Positive	Regulations
	Volumetric risk	Positive	Open access
CCGT Power Plant	Electricity tariffs	Positive	Competition/regulations
	Gas Tariffs	Negative	Competition/regulations

Source: Based on Integrated Cash Flow Model using @RISK v7.5.

6.8.0. The World Bank Benchmarked Sankofa Gas Project

The World Bank performed both financial and economic analysis for the Sankofa Gas Project (SGP). A US$9.8/MMBtu gas price, a discount rate of 10%, and a total cost of US$7.9billion were estimated for the project with

20years duration. This generated total revenues of US$14billion and NPV of US$4billion as indicated on Table 46.

Table 46: World Bank Benchmark

World Bank Benchmarks	Prices	Total Project Capital Cost US$	Total Revenue US$	Discount Rate	NPV US$
SGP	9.8$/mmbtu	7.9billion	14billion	10%	4billion

Source: World Bank (2015).

The World Bank Sankofa Gas Project is a confirmation of the fact that non-associated gas projects are high-risk investment projects in Ghana and will require higher commodity prices of US$9.8/MMBtu to remain viable. There is an interconnectedness between the four components of the integrated gas system. Whilst upstream gas production is dependent on gas demand of the CCGT, the GPP and the transmission pipelines are required to process and transmit associated gas to the CCGT.

The GPP is to process the associated gas and is a cost component to final gas prices. The transmission pipeline will be financially and economically efficient when transmitting multiple sources of gas at full capacity. Lower downstream gas prices are also important to the viability of the CCGT. There are four benefits of linking upstream gas to downstream power plants.

1. The Ghana government will get revenues from their share of oil, gas, and condensates royalties/taxes from private investors.
2. Supply of LPG to households and the local market.
3. Contributing to cheaper energy supply to ensure energy supply security in the country.

4. Additionally, domestic gas will displace LCO importation cost and investments into LNG plants in the short term. It is, therefore, cheaper to rely on domestic gas (World Bank, 2015).

The availability of sufficient fuel supply sources including gas, even though expensive, means the existing power crisis will be solved. This means there will be macroeconomic stability and a higher potential for economic growth in Ghana as each percentage point of economic growth in the economy is worth US$500million to the economy (World Bank, 2015; IMF, 2015).

6.8.1. Alternative Gas Consumption: A Fertilizer Plant

A major challenge common in the nascent gas industry in Ghana is getting large and small-scale gas consumers able and willing to pay economic tariffs for reliable and adequate gas supply. The power sector demonstrated consistency in serving as a large-scale end consumer of gas. However, credibility problems, increasing inefficiencies, mounting debt liabilities of wholesale gas and electricity buyers are raising serious concerns effecting the viability of the gas value chain.

As indicated above, the era of cheap power is ending in Ghana. The power sector alone cannot sufficiently meet the market requirements of the gas industry since a monopsony structure is created in the existing SBM of GNPC-GNGC-VRA firm structural model with its inherent challenges. MBM: B will require multiple large to small-scale downstream gas consumers which are able and willing to pay economic tariffs to avert the existing market concentration risk to only the power sector as mid-to long-term risk mitigation measure.

Why a fertilizer plant in Ghana? Agriculture contributes about 18.9% of Ghana's GDP as of 2016 and employs about 44.7% of the population especially rural communities and women as indicated in Chapter Two (Structure of Economic Growth Rate in Ghana). The crops sector being the leading contributor of 14.5% to agriculture (Ministry of Finance Budgetary Statement, 2017). The application of fertilizers mostly for cereal production including maize, rice, millet and sorghum and other crops accounts for 66.2% of the total agriculture subsector contribution to GDP. The production of these cereals requires the application of fertilizers mostly NPK and urea for higher yields since soils are increasingly losing their fertility (Ministry of Food and Agriculture, 2010).

To achieve this, a fertilizer plant utilization is considered because the other monetisation options are not viable in Ghana in the short-term considering the volumes of gas available. For example, an LNG export market requires large volumes of gas reserves and a destination market and possibly a non-existent domestic market for the gas. However, there is a domestic demand for gas in Ghana; yet, the gas reserves are not sufficient to meet this domestic demand or an LNG export project.

The Gas-to-Liquids (GTL) and Methanol Production are not priorities to the Ghanaian economy as studies from Nexant (2010), ECA (2014), Emos (2010), World Bank (2013) and the Ghana Gas Master Plan (2015) have suggested. The gas-to-power project has been the top priority followed by use in a fertilizer plant. Investments in a fertilizer plant is considered a strategic option for Ghana’s gas utilisation (Gas Master Plan, 2015). For the different gas utilisation options, methanol production, LNG exports and GTL projects would require significant gas reserves. In Ghana, nonetheless, these reserves are marginal. A fertilizer plant, on the other hand, with the increasing domestic demand, requires relatively small gas reserves.

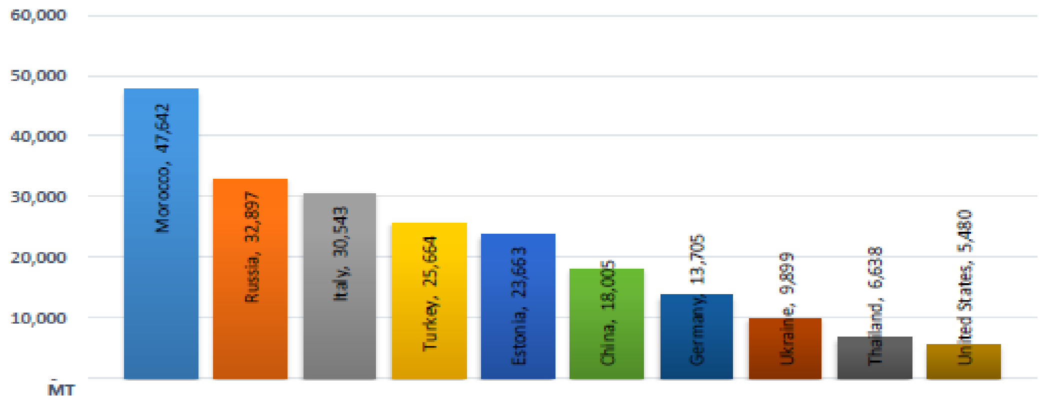
Additionally, fertilizer products have a guaranteed domestic demand for agriculture purposes. A fertilizer plant would replace or eliminate fertilizer import bills on the government of Ghana budget. This will make available funds for other equally important government expenditures. It is, also, a priority area of investment for government to increase the contribution of the agriculture sector to the overall GDP growth rate of Ghana.

6.8.2. Viability of Fertilizer Plant Investments in Ghana

The Ghana government has a fertilizer policy aimed at developing a competitive fertilizer subsector of quality, affordable and adequate fertilizer production and importation. The policy framework would be achieved mainly by providing appropriate incentives for investments into fertilizer production through effective funding mechanisms for fertilizer manufacturers and importers. The Ghana government intents to encourage domestic production of fertilizers through appropriate targeted tax reliefs, and tariff regimes. The policy is envisaged to be consistent with regional and international prevailing Economic Community of West Africa States (ECOWAS), Africa Union (AU) and other international policies on fertilizer.

However, there are currently no primary production of inorganic fertilizers in Ghana. Majority of the fertilizers consumed in Ghana are imported, blended and distributed through a network of wholesale and retail agro-dealers. These imports come from 10 main countries including Morocco (29%), Russia (17%), Estonia (16%) and Italy (15%) as indicated on Figure 34.

Figure 34: Fertilization Importation Countries into Ghana



Source: AfricaFertilizer.org (2017).

In 2016 there have been about 239,884 Million Tonnes of fertilizers imported into the country as indicated on the Table 47. The top five fertilizer imports into Ghana include NPK, 55% of all fertilizer imports, Urea 16%, Ammonia sulphate 10%, MOP (Muriate of Potash) 6%, TSP (Triple Super Phosphate) 6% and other fertilizers 7%.

Table 47: Fertilizer Importation into Ghana (000-Million Tonnes)

Fertilizer Name	2013	2014	2015	2016
NPK's	117,047	44,880	138,140	132,632
Urea	36,104	202	18,348	39,035
Ammonium sulphate	54,863	6,282	64,015	23,268
MOP	19,849	22,715	18,707	13,842
TSP	47173	21258	32052	13802
Other fertilizers	23051	15746	18895	17305
Total fertilizer for agric (MT)	**298,087**	**111,083**	**290,157**	**239,884**

Source: Africafertilizer.org, (2017). MOP-Muriate of Potash; TSP-Triple Super Phosphate

How can Ghana develop a domestic fertilizer production plant? Essentially some viability questions are asked: it is known that there is a domestic demand for fertilizers but if fertilizer would be produced in Ghana, would local fertilizer prices be competitive with imports. Are there adequate availability of raw materials? Government policy on fertilizer intents to support domestic fertilizer production through tax incentives but will these be competitive with other regional competitors such as Nigeria. Can a Ghana Government fertilizer subsidy support a local fertilizer industry?

The fertilizer plant will require relatively cheap gas prices to be viable. However, existing downstream gas prices in Ghana are relatively expensive at an average price of US$8.7/MMBtu under the SBM where GNPC is the aggregator of upstream gas and buys from IOCs. Domestically produced gas cannot be sold below the benchmarked WAGPCo gas prices of US$8.6/MMBtu according to one interviewee [Downstream-PURC]. These prices are unsustainable for a viable fertilizer plant. Sen (2015), confirms more appropriately that gas prices are set by allowing price formation mechanisms and providing subsidies directly to eligible consumers. Under certain circumstances, the prices of upstream gas are intentionally kept low to provide incentives and subsidy for the viability of some industries (Sen, 2015), therefore a fertilizer plant in Ghana can benefit from government intended gas price subsidy. FAO (2015) noted that, the Ghana government spends US$63million annually on fertilizer subsidy and this amount can serve as leverage for investing into a domestic fertilizer plant.

Ghana is producing natural gas from other gas fields such as the Greater Jubilee fields and TEN. To this end, a dedicated natural gas reserve for a fertilizer plant is not farfetched. TEN is an oil and gas project for which associated gas can be offered at a relatively cheap and competitive price to a fertilizer plant in Ghana whilst waiting on the gas industry to offer lower downstream gas prices in the long run. As indicated in Chapter Four (Table 23) for a typical Ammonium plant to be viable, requires gas prices not more than US$2/MMBtu in Ghana. A combined Ghana government initiative of subsidizing upstream associated gas prices with a dedicated project such as TEN can support a viable domestic fertilizer plant.

As it is the case in India gas prices to a fertilizer plant are regulated by the state (Sen, 2015). Gas is used as an input to urea production; alternatives to domestic gas supply are LNG imports, naphtha, fuel oil/Low Sulphur Heavy Stock (LSHS) and urea imports. Out of these substitutes, domestic gas has exhibited the least price volatility as prices are controlled at low levels. The India fertilizer sector accounts for 36% of domestic gas consumption and 20% of the consumption of LNG imports. Ghana as well can dedicated a proportion of domestic gas production and LNG importation as feedstock to a fertilizer plant to guarantee secured gas supply to the plant.

The Indian fertilizer industry case is based on the government “self-sufficiency” policy, which required all naphtha and fuel oil/LSH urea-manufacturing plants to be converted to gas-based plants with the view of greater use of domestic gas in urea production. The prices of domestically manufactured urea have been linked with the price of domestic price of gas. However, the retail prices of urea (to farmers) are subsidized by about 50%, which are paid directly to eligible consumers (Sen, 2015). The demand for gas in fertilizer production is currently being constrained by inadequate domestic supply. However, the question remains as to whether customers in this category would be willing and able to pay economic prices, which could incentivise new gas exploration and production (Sen, 2015).

Fertilizer subsidise: The Ghana government subsidizes 50% of final NPK and Urea prices to farmers in Ghana. This amounts to US$63million yearly (FAO, 2015). Sen (2015), however, concludes that, this subsidy could be managed if the amount of money used for fertilizer importation are instead used to invest into a local fertilizer plant. Alternatively, government could use revenues from gas royalties and taxes to finance the higher subsidy bill required for domestic fertilizer production (Sen, 2015). Ghana government can use royalties and taxes from gas projects to subsidize domestic fertilizer plant cost or as incentive to lower downstream gas prices intended to a fertilizer plant.

LNG supply sources can supplement fertilizer plant requirements in Ghana. Transnational gas pipelines such as WAGP can feed into a fertilizer plant in Ghana. However, Sen (2015), noted that a Ghana government gas pricing policy reform will be required to provide an appropriate gas price to a fertilizer plant either through a government gas subsidy price or rationing more cheaper gas to the fertilizer plant since the current cost of gas from current supply sources are uncompetitive for plant viability.

6.8.3. Fertilizer Plant Viability-African Perspective

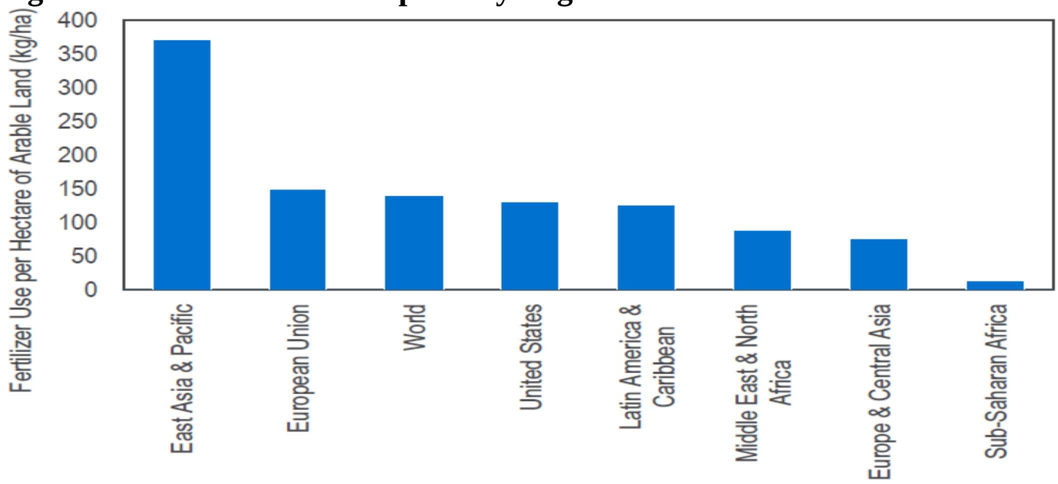
Agriculture in Africa accounts for 15 percent of GDP or more than US$100billion annually. In Sub-Saharan Africa, agriculture accounts for over one-third of GDP and exports earnings and employs over 60 percent of the population (Khemka, 2018). However, Africa's natural gas and fertilizer consumption levels are modest relative to its size of population. Uneven wealth distribution, lack of creditworthy off-takers to support large-scale gas-based projects, political instability and the uneven distribution of indigenous energy resources are some of the factors that have hampered the uptake of natural gas in the energy mix of the region (Khemka, 2018).

Improved natural gas supply and availability are essential for Africa to develop economically. Political and regulatory stability are critical for the development of the fertilizer sector (Khemka, 2018). Natural gas outputs in Africa originates from Egypt and Algeria, which account for 70% of production. Nigeria has the largest gas resources base. Nigeria gains in gas production will depend on the establishment of bankable commercial structures for the gas sector. The Nigerian government needs to redefine the role of public companies, improve regulations and reform gas prices to enable adequate investments into gas-to-fertilizer plants (Khemka, 2018).

Urea demand in Africa is estimated to be close to 5million tons in 2017, with around 90 percent consumed in direct fertilizer use for food production. There is low use of fertilizer in Africa and Sub-Saharan Africa. In 2006, the Abuja Declaration was adopted to encourage the usage of fertilizers in Sub-

Saharan Africa from less than 10kg/hectare to at least 50kg/hectare by 2015 as fertilizer application rates per hectare in Sub-Saharan Africa are the lowest in the world at an equivalent of 3% of Asia and 9% of North America's application rate (Khemka, 2018).

Figure 35: Fertilizer Consumption by Region



Source: Khemka (2018).

Sub-Saharan Africa represents about 15 to 20 percent of fertilizer consumption which presents an enormous opportunity for fertilizer growth given the below average nutrients application rates. The uncultivated land in Sub-Saharan Africa, which is close to 50% of the global uncultivated land available, will support the cultivation of crops. The power sector consumes half of Africa's gas resources and there is room to add fertilizer capacity, especially in Egypt, Equatorial Guinea, and Nigeria and on the west coast (Ghana) where there are increasing interest to monetize new gas finds. There are examples of fertilizer production plants in operation or developmental stage in Africa as indicated on Table 48.

Table 48: Africa Ammonia/Urea Capacity Development

Company	Location	Capacity	Start-up/Expected Start-up
Misr Oil Processing Company	Damietta Egypt	650kton urea, 400kton ammonia (MOPCO-2) 650 kton urea, 400 kton ammonia (MOPCO-1)	Dec-16 Jun-15
Indorama Eleme Fertilizers & Chemicals	Port Harcourt, Nigeria	1.4million tons per year urea, and 820,000 tons per year ammonia	Mar-16
Riaba Fertilizers	Riaba Equatorial Guinea	1.5 million tons ammonia/urea complex	Post 2021
Chemical Industries Holdings (Kima)	Aswan, Egypt	430,000 tons per year ammonia plant, 576,000 tons per year urea	Post 2021
Brass Fertilizers	Brass Island Nigeria	1.3 million tpy urea/770tpy ammonia	Post 2020

Source: Khemka (2018).

Egypt is keen to develop integrated ammonia/urea production facilities despite the diversion of its natural gas supply for electricity generation. Fertilizer plants competes for natural gas in LNG and power projects in Africa and it is therefore more difficult to secure financing for fertilizer projects in Africa. As more urea capacity are commissioned in the next few years, Africa may make the switch from being a net importer to a net exporter of urea and not to rival the giant Middle East producers such as Qatar (Khemka, 2018). African urea will be applied to African farms. Fertilizer plants operating cost are expected to vary from country to country, but Africa as a region will have relatively low operating rates due to feedstock supply issues and low production rates in politically sensitive areas at least in the near term (Khemka, 2018).

A fertilizer plant is viable in Ghana; however, this will require support from the government in developing a “self-reliant” fertilizer policy where domestic gas production are used as feedstock to a fertilizer plant. The Ghana government needs a gas pricing policy reform to dedicate lower priced gas projects such as TEN to the fertilizer plant. Government intended subsidies could be provided as investment advantage to build integrated gas-to-fertilizer plants in Ghana.

Finally, the Ghana government can enter into long-term contracts as Sen (2015) suggested with some of these African countries (Egypt, Nigeria and South Africa) to procure raw materials such as urea or natural gas for integrated gas-to-fertilizer plants in Ghana. Additionally, the government through joint venture fertilizer plant project financing partnerships with private investors can secure long-term gas supply contracts through LNG and long distance pipeline (WAGP) for integrated gas-to-fertilizer plants to take advantage of vast gas resource base in a country such as Nigeria. These arrangements could offer cheaper gas prices and raw material cost to Ghana compared to the international fertilizer markets.

6.9.0. Chapter Summary

In conclusion, natural gas production cost is high in Ghana; hence, cannot support any use requiring cheap gas. The government could reduce its tax and royalty burden to reduce the cost of gas production to some extent; but, even then, local gas will be costly. Imported gas is likely to compete with local gas in the future if excess supply becomes a normal feature of the global gas market. Transport and processing tariffs are inappropriately set and are adding to the overall local gas supply cost; this needs to be revised to make gas more affordable. Ghana cannot expect low cost electricity using gas supply as the wholesale purchase tariff cannot be priced less than US$0.09cents/kWh. The bulk power purchasers (VRA and ECG) will have to be prepared to pay at least this price. Besides, the gas sector is a risky business and any hold-up at the consumer end will jeopardise the viability of the entire supply chain.

CHAPTER SEVEN

REGULATING THE NATURAL GAS INDUSTRY IN GHANA

7.0. Introduction

Chapter seven (7) focuses on the third objective of the study: to develop suitable regulatory and governance arrangements for the gas industry in Ghana. The chapter is divided into four parts: the first section identifies the various stakeholder problems in the gas industry regulations, the second considers developing effective regulations for the gas industry, section three focuses on regulatory governance arrangements while the final section looks at how to develop gas industry regulatory policy and presents the conclusion.

7.1.0 Regulatory and Governance Arrangements

Lack of effective regulations is considered a major problem in attracting infrastructure investments into the nascent gas industry in Ghana (Fritsch and Poundineh, 2016). The nascent gas industry in Ghana requires effective regulations to enhance sufficient infrastructure investments (Poudineh and Jamash, 2014). Contrarily, the Energy Commission argues,

'*We don't need a new Gas Sector Law*' [Midstream-EC].

Currently, no specific law governs the electricity industry in Ghana. The Energy Commission Act regulates the electricity and gas industries. Therefore, a new law will mean changing the Energy Commission Act, passing a new Act all together or removing the corporate clauses in the Energy Commission Act. Either way, the Energy Commission Act has to be either repelled or amended [Midstream-EC].

7.1.1. Regulatory and Governance Problems in the Gas Industry in Ghana

The structural and business viability analysis in chapters five (5) and six (6) identified three (3) important regulatory lapses in the nascent gas industry in Ghana:

- Regulating upstream aggregation of gas, especially with the current monopoly structure of GNPC.
- Regulating the transmission pipeline on open access and third party basis for multiple users and establishing the Natural Gas Transmission Utility (NGTU).
- Regulating the gas processing plant and transmission pipeline tariffs to reflect final downstream gas prices.

Additionally, the stakeholder consultation identified three (3) major structural and regulatory issues in the nascent gas industry in Ghana. They are as follows:

- Inappropriate tariff setting;
- Lack of clarity of roles and responsibilities and;
- Lack of regulatory independence and effectiveness

The Millennium Challenge Account (MCA) Team, with core personnel from the power sector in Ghana, as well, identified lack of effective governance and regulatory framework as a major problem in the nascent gas industry in Ghana. Among the regulatory problems identified are the need for effective sector specific legal-framework for IPPs, the need for full cost recovery, transparency in tariff-setting processes, absence of gas pricing and allocation policies regulations and the independence of regulatory bodies.

7.1.2. Theoretical Background

Transaction Cost Economics (TCE) provides the lens through which regulation in the gas industry is analysed (Spanjer, 2009). In the nascent gas industry in Ghana, the main challenge is the hold-up and lock-in problems with downstream consumers (VRA and ECG) in non-payments of consumed gas, which is likely to affect the gas value chain. Long-term contracts between gas producers and the main aggregator (GNPC) have tied-in IOCs' investments into government opportunism of ensuring energy security to the detriment of investor uncertainty in inefficient gas tariffs and non-payments. Governance structures capable of eliminating the hold-up and lock-in problem, therefore, must be created (Spanjer, 2009).

Asset specificity of essential infrastructures such as transmission pipelines cannot be redeployed without loss of productive value (Williamson, 2010). Moreover, there are existing open access regulations on the GNGC and WAGP transmission pipelines which are not effective. The uncertainties and complexities of transactions in the nascent gas industry, as well, have led to higher investment risks affecting the supply components of the gas industry and flaws in regulatory arrangements (Joskow, 2000; Newsbery, 2004).

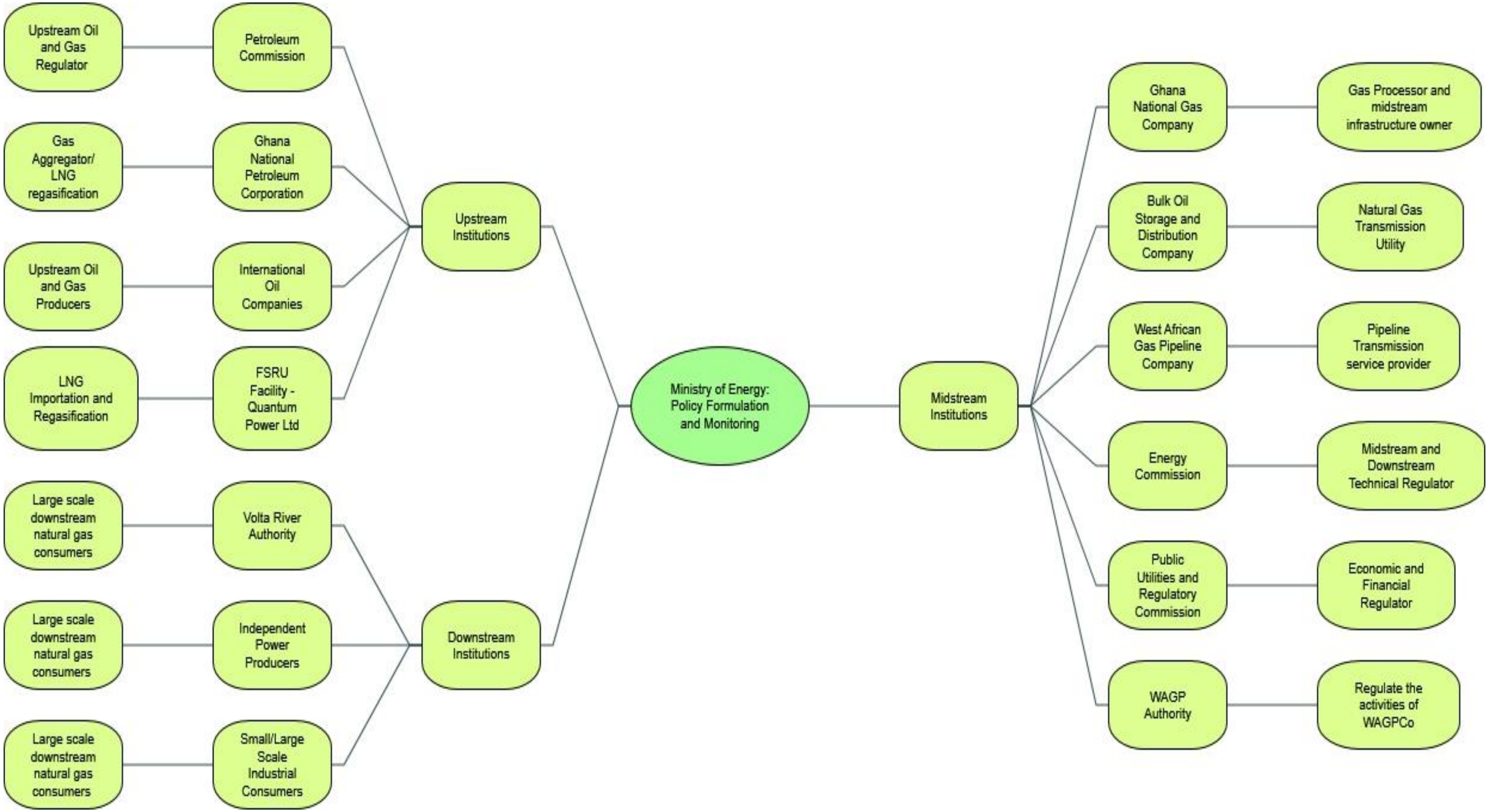
The SBM proves to be inefficient as the current structure of the gas industry in Ghana (Spanjer, 2009) due to the hold-up and lock-in problems created. New structural models: MBM: A and B will promote short-term contracts, increase bilateral trades between many more players and introduce gas suppliers/traders with the possibility of developing spot trading. These structures introduce new challenges of economic regulations in tariff setting, infrastructure access regulations and regulatory governance. The major concern, however, is the regulatory uncertainty/risk, which hampers investments (Spanjer, 2009).

The interplay of asset specificity, investment uncertainty/risk and industry structure according to Spanjer (2009) will determine the regulatory regime and governance structures required for improving infrastructure investments in the nascent gas industry in Ghana. This proposition is based on the third objective of the study: How can an effective regulatory framework be developed for the nascent gas industry in Ghana?

7.2.0. Governance Framework of the Gas Industry in Ghana

Traditionally, the main actors involved in the regulatory framework of the gas industry as contained in Chapter Two (section: 2.5.3) are the Ministry of Energy, Petroleum Commission, Energy Commission, Public Utilities Regulatory Commission, GNPC, GNGC, BOST and VRA. There are IOCs including Tullow Plc, Anadarko, Kosmos, ENI and ExxonMobil as well. Also, there is the transnational pipelines, WAGP with WAGPCo as the service provider and WAGP Authority as the regulator as indicated on Figure 36 with their areas of jurisdiction and responsibilities.

Figure 36: Institutional Arrangements in the Gas Industry in Ghana



Source: NVivo QSR 11.

The Figure 36 indicates the institutional arrangements of the various gas industry organisations and their areas of jurisdictions as well as duties and responsibilities. The Ministry of Energy is the overall policy formulator and monitors the entire energy sector. In the upstream, there is GNPC as the gas aggregator with the Petroleum Commission as the upstream oil and gas production regulator. The IOCs and other investors are the main investors and infrastructure providers for oil and gas production/suppliers.

The midstream governance structure is dominated by government agencies: Energy Commission as technical regulator, PURC as the economic and financial regulator, BOST as the licensed NGTU and GNGC as the midstream infrastructure owner (gas processing plant and transmission pipeline). WAGPCo offers transmission services regulated by WAGP Authority. In the downstream, VRA currently dominates consumption but other Independent Power Producers (IPPs) and large-scale industrial consumers are expected to participate in the gas industry as alternative consumers.

Figure 36 provides a clear demarcation of the current institutional arrangements of roles and responsibilities of state agencies and private players in the nascent gas industry in Ghana. These players, as already mentioned, are categorised into upstream, midstream and downstream operational jurisdictions with each player assigned their role and responsibility. However, according to the stakeholder consultations, an interviewee from the private companies, indicate that there are numerous gas industry state regulatory agencies with conflicting roles and responsibilities. Yet, there is no substantive gas industry regulatory framework or a policy objective governing the development of the industry in Ghana as stated by one interviewee [IOC-ENI-Ghana].

The IEA (2012) recommended that there should be an independent regulator for the gas industry instead of the existing splitting of roles and responsibilities between different governmental agencies. There are too many players requiring an independent gas industry regulatory authority with a clear policy objective and a regulatory framework for the gas industry in Ghana. The rest of the chapter is, thus, dedicated to developing an effective and an independent regulatory authority for the nascent gas industry in Ghana.

7.3.0. Independent Gas Regulator for the Gas Industry in Ghana

Contrary to the various challenges identified in the gas regulatory framework and governance arrangements in Ghana, establishing an independent regulator for the gas industry is seen as an alternative regulatory process compared to the current regulatory structure involving several state agencies (Eberhard, 2006). An independent gas regulatory Authority would provide the solutions to the current regulatory challenges. This independent regulatory authority will focus on gas sector regulations.

The government of Ghana currently holds a high commercial interest in the gas industry. The shift from the SBM to MBM models will involve the increasing role of other stakeholders in gas infrastructure investments, production/supply, trading and consumption. This will require an independent gas regulatory authority. The independent regulatory authority will preserve continuity in the setting of rules, avoid political interference in business decisions and regulatory risks and maintain high standards of expertise and professionalism (Carpros, 2003).

This independent gas regulator should be established on the premise of high regulatory commitment based on a gas sector law. The independent gas regulator would have a clear mandate and a set of specific objectives for the gas industry. It would be autonomous and accountable to the state and stakeholders, transparent in their activities and display a high level of integrity and participation from all the industry stakeholders (Eberhard, 2006).

In addition, this independent regulator will require strong regulatory commitment, good governance arrangements and competent institutional capacity (Enerhard, 2006). The regulator must consider the needs of the poor and be able to develop quality regulations for the benefit of the very poor through pro-poor tariff and targeted subsidies for poor consumers (Baker and Tremolet, 2003) and gas-to-power lower tariffs for lifeline consumers.

All these will be effective when an independent regulator is in place providing better monitoring and quality enforcement than the several governmental agencies (Baker and Tremolet, 2003) in Ghana. Tariff setting should be depoliticised to reduce cost recovery risks. Regulatory decisions, on the other hand, must protect consumers and ensure that pro-poor tariffs are whilst ensuring business viability (Eberhard, 2006).

What is most needed to achieve effective regulation is a stable energy policy with a section on the gas industry or a gas law. The law or policy will set long-term goals and foster clear rules for the assessment of each case of market failure and possible solutions, giving authority to an independent gas industry regulator (Leuch, 2012; Eberhard, 2006). The independent regulator will, thus, need to develop effective regulations for the nascent gas industry.

7.3.1. Effective Regulations for the Gas Industry in Ghana

The independent regulatory authority should be concerned with designing effective regulations[38] for the nascent gas industry and must recognise that these are similar to developing regulations for a fragile state. They should be guided by the following: preventing monopoly abuse of market power, expanding infrastructure access, improving management performance and restricting political opportunism (Body of Knowledge on Infrastructure Regulations, 2017).

The concept of introducing a new structural formation will require a dense regulatory framework (Correlje, 2008). The choice of VIM/SBM or MBM will require slightly different regulations. Whilst VIM/SBM requires more regulations, a move towards MBM lessens regulations and allows the industry to self-regulate on economic terms. An effective regulatory system should be aimed at improving the overall gas sector performance and be able to reassure investors of full cost recovery and protection from unavoidable levels of price reduction (Newbery, 2004). The regulatory system should address the

[38] Effective regulation is considered as a repeated game with periodic reviews and need for regulatory commitment, stability and simplicity, robustness and proof against capture and manipulation and public acceptability. Practical regulatory solutions prove more helpful than theory, providing solutions and proposing alternative superior workable solutions (Newbery, 1997).

most critical challenges in the industry and form a path towards the eventual development of formalised regulatory institutions (Body of Knowledge on Infrastructure Regulations, 2017).

These should be guided by meeting the critical basic immediate needs in the industry and laying the foundation for a more effective future regulatory system. Such critical basic needs are to meet market fundamentals and provide the right incentives for infrastructure investments. The first step towards an effective regulatory system is stakeholder engagement where the exact needs of the regulated bodies and interested parties are considered to inform policy formulations. Regulations are considered effective with sound regulatory governance when the regulatory institutions are strengthened, there is in existence a rule of law and regulatory credibility of the regulatory agencies, able to attract and sustain infrastructure investments (Body of Knowledge on Infrastructure Regulations, 2017).

The new gas industry regulatory framework will involve breaking down the current regulatory structure into three main precepts discussed below and indicated in Figure 37.

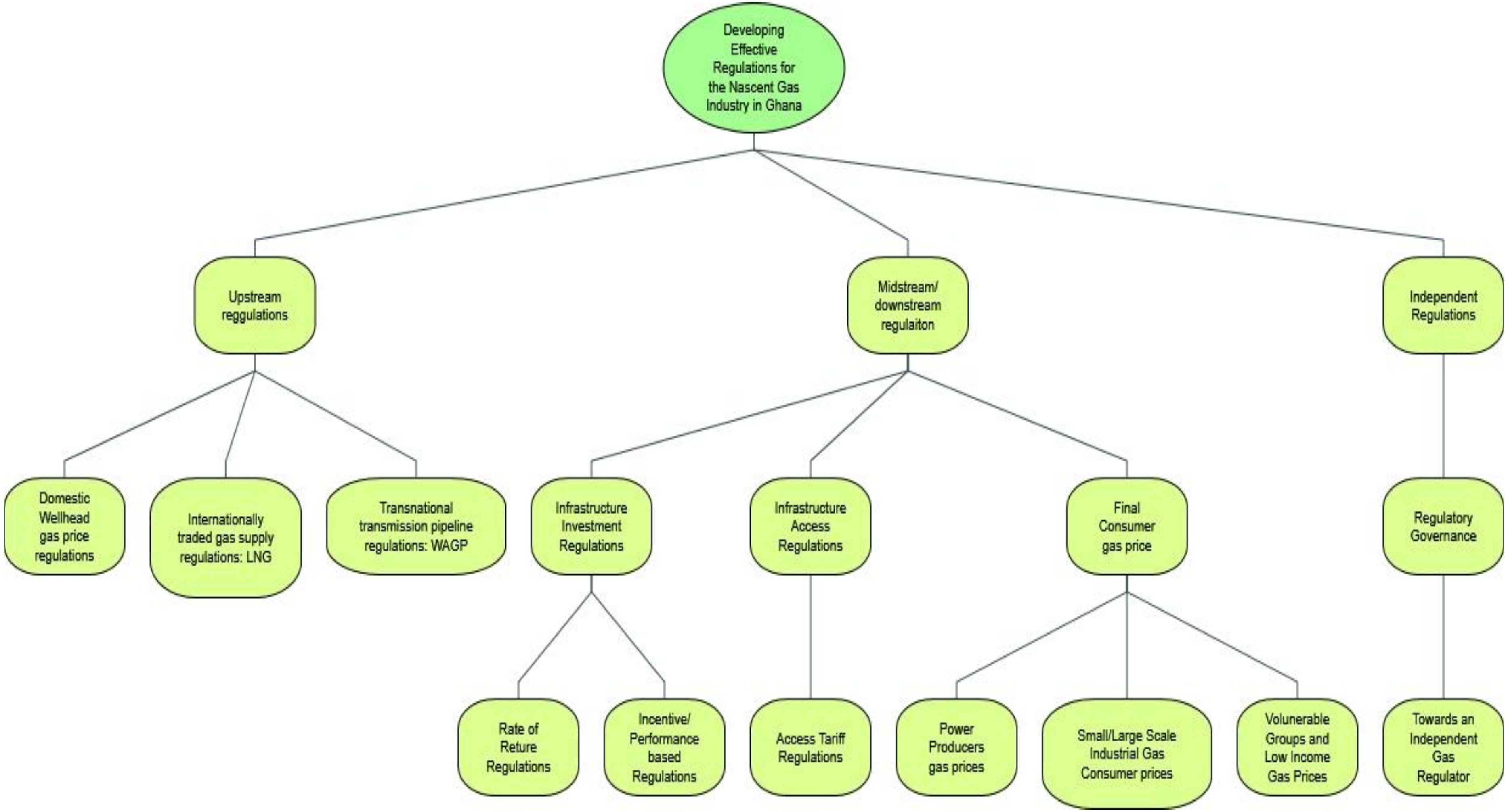
- Upstream gas production/supply regulations, which include domestic wellhead gas production and other supply sources such as LNG, and transnational pipeline regulations/negotiations.
- Midstream/downstream regulations including infrastructure investment regulations (rate- of-return and incentive regulations), infrastructure access regulations (open access and tariff setting regulations) and final consumer

gas price regulations (IPPs, small/large scale gas consumers, vulnerable and low-income gas consumer prices).

- Independent gas regulations to include providing a sound regulatory governance system aimed at developing independent gas regulator.

Poor institutional arrangement was identified as another challenge in the nascent gas industry in Ghana. Institutionally, the gas industry value chain should be divided into three major sectors: upstream exploration, development, and supply of gas, midstream processing and transportation and downstream distribution and consumption (Dong et al., 2017). The current gas industry structure of VIM/SBM allows an integrated/single gas supplier controlled by the state. A regime/structural change of MBM will involve the separation of potentially competitive segments such as upstream gas production/supply and trading activities from transmission and distribution activities (Correlje, 2008). The new structure will require effective regulations different from existing regulations.

Figure 37: Effective Regulations for the Nascent Gas Industry in Ghana.



Source: NVivo QSR 11.

7.3.2. Upstream Gas Production/Supply Regulations

The upstream production/supply of natural gas regulation/negotiation will involve domestic wellhead prices, transnational transmission pipeline supplies, LNG and the regasification units.

7.3.3. Upstream Natural Gas Commodity Price in Ghana

There are disparities in the commodity prices of upstream gas produced in Ghana. There is a price differential between associated gas and non-associated gas. Upstream gas commodity prices are negotiated between GNPC and upstream producers (IOCs). There are two streams of upstream gas with different cost structures: associated and non-associated gas. GNPC acts as the single national gas aggregator, which is a monopsony. The role of the aggregator according to one interviewee is:

> '*Is to ensure the commercialisation of upstream gas resources by providing the right commercial securities and arrangements for gas to be sold to credible customers. To ensure continuous supply of gas to power plants. Ensure that upstream gas producers are incentivised. GNPC is also involved in LNG commercialisation in the country*' [Upstream-GNPC].

How is the gas commodity price determined? Natural gas is produced deep-offshore in Ghana from two main fields: Jubilee and Sankofa Gas Project. TEN and Greater Jubilee are other marginal deep-offshore fields. Each offshore field has a unique cost structure (EIA, 2016). Main offshore cost drivers include water depth, well depth, reservoir pressure and temperature, field size and distance from shore (EIA, 2016).

There are substantial cost differentials between offshore associated and non-associated gas production. The commodity price of gas is dependent on the upstream production cost and crude oil prices (EIA, 2016). Lower production cost and higher crude oil prices will see the exploration and production of several fields and enhanced production techniques and vice versa.

The cost of bringing gas from upstream to downstream depends on each production field's contracts and third party midstream infrastructure providers. Dry gas (non-associated gas) which does not require processing incurs the lowest cost (EIA, 2016). Wet gas (associated gas) which includes NGLs that require fees for processing tend to have higher cost. Dry gas incurs a cost of US$0.35/Mcf for gathering and transportation whilst wet gas requires fees for processing, fractionation and transport. Gathering and processing fees often range from US$0.65 to US$1.30/Mcf while Fractionation fees range from US$2 to US$4 per barrel of NGLs recovered. These are the costs from deep-water operations in the Gulf of Mexico in the USA (EIA, 2016).

The case is, however, the opposite in Ghana. Non-associated gas production costs are much higher compared to associated gas because of the shared cost recovery with oil production. In some instances, associated gas is flared in Ghana and in neighbouring Nigeria. More than 60% associated gas is still flared (IEA, 2016), and when produced, these are sold at very low prices. GNPC has negotiated for the first 200BCF of associated gas from the Jubilee

Fields to be delivered at zero cost. This volume belongs to Ghana, GNPC is acting on behalf of Government to receive the gas. One interviewee noted that:

> '*The need to incentivise upstream associated gas production by placing an economic value on it even though the contractual agreements says that if the contractor has no use for the associated gas it should be given to GNPC at zero cost. But let's reconsider this law properly*' [Upstream-GNPC].

There was virtually no exploration for gas in Ghana just as in Nigeria. Most of the gas discovered came from exploring for oil (Anothny and Anyadiegwu, 2013). As a result, oil was seen as the main aim in the Jubilee field production although 50% of new deep offshore wells drilled in 2011 and 2012 produced both oil and gas (EIA, 2013).

Associated gas was, therefore, flared or re-injected into wells to maintain pressure and enhance crude oil production in Ghana. However, flaring natural gas is harmful to the environment (World Bank, 2015), the Ghana 2016 Petroleum Bill (Act 919) prohibits flaring except on technical basis and allows reinjection for technical and operational reasons. Associated gas has a no/lower production cost as in this instance, crude oil revenues are used to fully cover the cost of these fields. Nonetheless, both oil and gas produced together are now considered in arriving at the viability analysis for developing a field (EIA, 2013). Field development costs are recovered from the sale of both crude oil and associated gas.

Associated gas prices are negotiated between GNPC, the Jubilee field and TEN field partners at US$2.8/MMBtu to give an economic value and to serve as an incentive for further gas exploration and production in Ghana [Upstream-GNPC]. Associated gas contains other rich gas liquids (NGLs) from which Liquefied Petroleum Gas (LPG) can be produced (EIA, 2016). The non-associated gas projects, on the other hand, need different commercial arrangements to be viable. Unlike associated gas, non-associated gas needs to be sold at an economic value that will fully recover all cost of production. As one interviewee noted:

> *'For non-associated gas, GNPC needs to pay full cost because of the high investment cost, and nobody will come put about US$7.9billion and won't get paid'*[Upstream-GNPC].

This raises the question of what factors GNPC considers in arriving at the non-associated gas commodity price. Full cost - capital expenditure-recovery factors must be considered. The cost of capital and the operating expenditure are the basic factors used in arriving at the commodity price as indicated by the same interviewee:

> '*In Ghana, it is quite clear that it is the cost of investments: the CAPEX cost of capital and OPEX. These are broadly the basis. Including the securities put up for the payment of the gas and country risk insurances. The price is indexed to either oil, replacement fuel or to a jurisdiction gas industry for example Henry Hub in the USA. And finally a profit uplift and a fair rate-of-return*' [Upstream-GNPC].

What is done to ensure an appropriate upstream gas commodity price in Ghana? The CAPEX for the SGP is US$3.9billion (World Bank, 2015). The OPEX is estimated at US$4billion according to the World Bank estimates. Total project cost from the SGP, thus, amounts to US$7.9billion. Why then is the SGP commodity price so expensive at US$9.8/MMBtu? According to the interviewed expert:

> *'In the price determination, capital expenses, operational expenses, the rate of return that we need to give the contractor to incentivise them to operate the field and other costs. Therefore, in the end we have US$9.8/MMBtu'* [Upstream-GNPC].

Obviously, the answer lies in the higher capital cost for SGP, the higher securities required, contractor incentives and government fiscal policy. Non-associated gas production is essentially more expensive compared to associated gas in Ghana. Close to half of the revenues from the sales of gas from the SGP are taxes and royalties to the Government (World Bank, 2015) and this has, obviously, been added to the final downstream price to reach US$9.8/MMBtu. The fiscal policies of the government, also, have an impact on the SGP gas price. The project is expected to generate US$3billion in only royalty payments to the government, and these are direct costs added to the final SGP gas price.

The securities provided for the SGP are many, consisting of several layers of interventions and recourses. These include the payment of designated GNPC receivables into segregated accounts; liquidity reserves in the forms of cash reserve, escrow account and letters of credit backstopped by an IDA

(International Development Association) payment Guarantee, a notional amount of IBRD (International Bank for Reconstruction and Development) Enclave Loan Guarantee and a limited Sovereign Guarantee. Additional to the securities is MIGA (Multilateral Investment Guarantee Agency) guarantees which are expected to support termination payments for financiers and private equity partners at the partner company level (World Bank, 2015).

The cost of these securities are considered very high and are contributing to the high cost of the SGP gas price. This is due to the liquidity risk associated with downstream consumers such as VRA and ECG non-payment problems and the need to de-risk the gas industry via debt and political risk insurance securities. Some of the risk identified by the World Bank (2015) group include Country level risk (political and governance risk, macroeconomics risks), energy sector risk (downstream power sector payment risk) and project risk (sankofa gas off-taker capacity risk, project preparation and implementation risk, and Sankofa/GNGC facility interconnection risk). A reduction in some of these risks, would lead to lower final SGP prices.

To reduce the SGP commodity price requires reducing the risk associated with the project and this will require reviewing the SGP project cost and implementing incentive regulation mechanisms to monitor project cost reductions as well as reviewing the government’s fiscal policy on gas production. In designing a regulatory framework for upstream gas commodity price in Ghana, considerations can be given to combining the different cost components of associated and non-associated gas to cross-subsidies each other.

In the MBM, regulating wellhead price of gas will be incompatible since each supplier will be allowed to negotiate their selling price with various buyers. However, in the SBM, there is a monopsony, which requires GNPC as the single gas aggregator to be regulated to ensure effectiveness of arriving at economic commodity gas prices. Ghana government can further reduce taxes and review fiscal policies on non-associated gas production to reduce the cross-subsidised commodity prices.

7.3.4. Regulating Transnational Transmission Pipeline Supplies

The main cross-border natural gas transmission pipeline in Ghana is the West African Gas Pipeline, which is owned and operated by the West African Gas Pipeline Company (WAGPCo). This transmit gas from Nigeria into the West African Sub-region and currently delivers gas to Benin, Togo and Ghana. In Ghana WAGPCo delivers gas at Tema and Takoradi thermal power plants enclaves operated by the VRA.

WAGP is in response to ECOWAS treaty on energy (article 28) which aims at ensuring effective development of energy resources in the sub-region through establishing appropriate coordination mechanisms to ensure regular supply of hydrocarbons through interconnected transmission pipelines. The West African Gas Pipeline Authority is established to enforce the regulations governing the pipeline. The West African Gas Pipeline Treaty between the State Parties (Ghana, Benin, Togo and Nigeria) and private partners (Chevron Nigeria Limited, Volta River Authority of Ghana, Shell Petroleum Development Company of Nigeria, Societe Beninoise de Gas S.A., and Societe Togolaise de

Gas S.A) establishes the principles and operations of WAGP. These transit countries of Benin and Togo are participants of the WAGP Treaty and therefore reduces pipeline transit risks.

The delivered WAGP gas price into Ghana is US$8.6/MMBtu set by WAGP Authority in consultation with all the stakeholders. This is the benchmark price for gas in Ghana. One of the reasons for higher domestic gas prices in Ghana is that, gas cannot be sold below the WAGP benchmark prices (US$8.6/MMBtu). WAGPCo charges a transmission tariff of US$5.03/MMBtu. WAGP has operated over a decade in Ghana and should be able to recover much of its capital cost. The WAGP Authority should as well be able to offer rate-of-return and incentive/performance regulatory mechanisms to deliver lower transmission services charge and lower gas prices in Ghana.

WAGP has operated over a decade without major political risk; however, there are several economic risk (World Bank, 2003). WAGP has been unable to meet its contractual gas supply obligations of 120,000MMBtu/d of gas to Ghana due to several reasons. The interviewee in this company noted that lower upstream prices in Nigeria is discouraging private producers; delays in passing the Petroleum Bill, which slowed investments in upstream gas projects [Midstream-WAGPCo]. Changes in market dynamics for gas demand in Nigeria due to emerging political dynamics where the government is investing into power generation. Vandalism of the transmission pipeline in Nigeria and pirates activities directly affecting offshore pipelines and inadequate infrastructure to transmit the gas into Ghana.

There are discussions on the re-utilisation of WAGP in Ghana for domestic transmission of gas from Takoradi (West) to Tema (East). This back/reverse flow technology is promulgated to reverse the flow of gas from West to East instead of the initial East to West flow. It is projected that, domestic gas supply to the West enclave will have excess supply and the East can benefit from these excess supplies. When domestic gas production begins to decline the LNG regasification plant at the East can equally use WAGP to supply gas to the West. However, access regulations, tariffs, and regulatory jurisdictions between WAGP Authority and regulators in Ghana need urgent clarification.

WAGP as an international transmission line, the best option would be to allow GNPC to take delivery of its gas and then use its own network to distribute it domestically. Involving an international pipeline in domestic distribution requires agreement at the ECOWAS level, which is not easy and will not remain within the jurisdiction of the local regulator. Clear role of WAGP as a supplier of foreign gas will make it easy to deal with this case. All domestic transmission and distribution networks should be the responsibility of the licensed NGTU. The regulator can then set the appropriate tariffs and monitor the performance.

7.3.5. LNG Supply and Regasification in Ghana

Global LNG markets are undergoing significant changes because of slowed demand in Asian Pacific: lower oil prices and American shale gas boom. These conditions have resulted in increased LNG spot trading; shorter-term contracts; and pressure to modify destination clauses in LNG contracts (EIA, 2017). LNG receiving terminals are considered gas supply sources (US Department of Energy, 2005). Ghana is taking advantage of global LNG markets to invest in FSRU infrastructure to regasify LNG as domestic gas supply option.

Ghana is currently under a stressed gas demand. Even with increased production from domestic reserves and transnational transmission pipeline supplies, gas demand in Ghana will outstrip supply. LNG is expected to play a major role in meeting future imbalances in demand and supply. Ghana will need to develop as a matter of agency new regulations for the supply of LNG and regasification. There are infrastructure investments led by public-private partnership in constructing Floating Storage Regasification Units[39] (FSRU) to receive LNG.

Developing a regulatory framework to integrate LNG supply is important to the development of the gas industry in Ghana. LNG is internationally traded and traders who need to import LNG must be licensed as LNG importers. LNG importation will provide flexibility to gas consumers (EIA, 2017). In the MBM, LNG supplies can be considered as another source of gas, which traders will negotiate prices between buyers and sellers. However, the FSRU is an essential cargo handling facility and any LNG ship has to use it before gas can be delivered locally. This facility has to recover its costs of

[39] FSRUs are gaining rapid global growth in investments due to their lower cost, faster schedule, commercial flexibility and reusable asset features of FSRUs compared to land based terminals, which cannot be relocated and must be regarded as sunk cost (Songhurst, 2017).

operation and investment and the independent gas regulator can set its tariff.

In regulating the FSRUs to recover their cost of investments and promote more investments, a summary report on LNG terminal regulation in France (2008) made the following LNG receiving terminals regulatory notifications: LNG FSRU investors, terminal operators and shippers expressed concerns for long-term price visibility. They also expressed interest in the rules governing the use of the facilities with the view to providing steady revenues to the operators, access by smaller shippers and ensuring the emergence of a secondary capacity market to improve gas supply flexibility and responses.

In regulating the FSRUs, the report made the following recommendations: establishing a long-term view for LNG tariffs (15-20years) and establish a tariff methodology to provide commitments to investors. Tariffs should be reviewed more frequently (4-5years) to ensure risk and reward sharing among players. Setting interest rates for the entire duration of the tariff and depreciation rates that encourages investments, which can balance between the debt payback periods and the economic life of the infrastructure.

Provisions should be made for exempted and regulated FSRUs, which are guided by rules regarding transparency and "Use-it-or-Loss-it mechanisms"[40]. There should be case-by-case studies for consideration of third party access exemption given the high financial risk.

[40] Use-it-or-lose-it (UIOLI) mechanism is intended to ensure the optimal use of the FSRU by giving shippers access to the infrastructure when capacity is physically available but usage by the primary holder. These are classified as ex-post and ex ante mechanisms (Summary Report on Regulations of LNG Terminals in France, 2008).

End-user gas are usually different from the LNG imported because of the heat content of the imported LNG may be different from the local market requirements and some of the LNGs may contain additional gas liquids (ethane, propane and butane) which must be stripped off methane before transmission to major consumers. The final consumer gas from LNG FSRU must be compatible with local consumer appliances and pipelines. Regulations should be able to address LNG interchangeability and quality standards in light of different LNG importations (USA Department of Energy, 2005).

The jurisdiction of the FSRU location as either upstream or midstream should be decided to ascertain the governmental agency responsible for the regulation of LNG regasification infrastructure in Ghana. The FSRU is located offshore within the remit of Petroleum Commission. However, Energy Commission is responsible for technical regulations of midstream and downstream gas infrastructure. The roles of these two agencies on the FSRU needs clarification. Energy Commission is however the midstream infrastructure regulator.

The Ghana Maritime will be required to provide security and ensure safety of the FSRU facilities and ships delivering LNG to Ghana. Energy Commission will regulate the design, construction and operation of the FSRUs, LNG pipelines, and storage facilities. Standards for operations, maintenance, fire protection and security at the facilities (USA Department of Energy, 2005). The Environmental Protection Agency of Ghana will provide safe-guide regulations to the LNG FSRU facilities. However, an independent gas sector regulator could provide all-inclusive LNG FSRU regulations in Ghana.

7.4.0. Midstream and Downstream Gas Sector Regulations

The need for infrastructure investments into the energy sector in Ghana is vast which the Millennium Challenge Account team estimated a total of US$4billion required into the power sector and US$200-280million/year. Ghana requires about 12,500MW of installed power capacity to industrialise according to the MCA team. Attracting infrastructure investments into power utilities will be forthcoming if investors can be guaranteed returns, which commensurate with their level of perceived risk (Alexander and Harris, 2005).

7.4.1. Gas Infrastructure Investment Regulations in Ghana

Four sources of capital are identified for infrastructure investments into developing countries: government own capital, capital from donor agencies and the private sector and revenues from the infrastructure operators (Body of Knowledge on Infrastructure Regulations, 2017). Each of these funding sources has its challenges and are mostly addressed by effective regulatory institutions. Largely government resources in developing countries such as Ghana are limited and are competed for in other priority areas such as in providing clean drinking water, health services and facilities and limits the role of government investments in providing energy sector investments. With the recent policy reforms in the energy sector, private sector capital is mostly relied upon in providing such infrastructures (Body of Knowledge on Infrastructure Regulations, 2017).

The private investor is mostly concerned about the risk of not recovering their sunk cost, setting commercially viable prices and tariffs that are sufficient to attract the right level of service quality and how their cash flows can cover their investments, operating cost and capital cost (Body of Knowledge on Infrastructure Regulations, 2017).

What regulatory framework can Ghana implement to attract and sustain infrastructure investments into the gas industry? PURC is responsible for economic regulation of the gas industry. One interviewee noted that, in setting gas prices and tariffs, three cost factors are determined: investment cost, rate-of-return, operating cost and volumetric risk [Downstream-PURC].

> '*PURC uses a combination of rate-of-return and incentive/performance base regulatory mechanisms in setting gas tariffs*' [Downstream-PURC].

PURC is developing a 'PURC Gas Transmission Guideline', which is a regulatory framework for infrastructure investments for pipelines and in this framework; the rate-of-return and incentives based mechanisms are used [Downstream-PURC].

The overall regulatory framework within which a private investor operates is an important determinant of the incentives for infrastructure investments and the broad parameters include return on capital, which regulators allow, treatment of depreciation, and incentives for efficiency provided for operating and maintenance cost and investment (Alexander and Harris, 2005). How effective are the rate-of-return and incentive/performance base infrastructure investment regulatory mechanisms?

7.4.2. Effectiveness of the Rate-of-Return Regulatory Mechanism

Rate-of-return (ROR) regulations enable firms to recover their investments cost with risk-free fixed rate-of-return (Cullmann and Nieswand, 2015). This is a cost plus regulatory mechanism whereby the regulator (PURC) sets the rate of return the utility can earn on its assets. Prices are fixed to allow the utility to recover all major cost and allow it to earn a specified rate of return (Canbini and Rondi, 2010).

The regulator (PURC) stipulates rules that determined the allowed revenues (Alexander and Harris, 2005). Rate-of-return or cost of service regulation has been the dominant regulatory mechanism regulators seek to maximise social welfare of consumers in natural monopoly markets (Aas, 2016). With the rate-of-return regulations, utilities have two goals: 1. to identify a fair rate-of-return on capital expenditures (CAPEX) for utilities so that, they can attract large amounts of investments needed to fund high fixed cost projects and; 2. To ensure that utilities investments are prudent (Aas, 2016).

The merit of these mechanisms are that, it creates a stable business environment in which large capital investments can be identified, financed and built (Aas, 2016). This is much recommended at the developmental stages of the gas industry where infrastructure requirements are high. A critic of the rate-of-return regulations holds that, the information asymmetries between utilities and regulators makes it difficult to accurately assess whether firms are minimising their costs. This relates to the regulatory capacity of PURC and their effectiveness in performing their regulatory oversight over utilities.

The Rate-of-return regulation is also criticised for its inefficiencies (Newbery, 1997) due to the Averch-Johnson effect when the rate-of-return exceed capital, companies are tempted to substitute capital for labour which reduces the employment of innovative talented personals increasing inefficiency (Cullmann and Nieswand, 2015). Rate-of-return regulations provide incentives for companies to overinvest in infrastructure and do not provide adequate incentives for productivity improvements (Aggarwal and Burgess, 2014). Empirical and theoretical evidence (Cullmann and Nieswand, 2015; Cambini and Rondi, 2010) confirmed that rate-of-return regulations are replaced by incentive/performance based regulations.

7.4.3. Performance/Incentive based Regulatory Mechanisms

One interviewee confirmed that, Rate-of-return regulations are replaced by incentives regulations [Downstream-PURC], as stated also by Joskow (2008). Incentive regulations are considered superior to traditional rate-of-return regulation (Jamasb and Pollitt, 2007; Joskow, 2014). Regulations have moved from simple cost recovery towards value addition (Aas, 2016).

Incentive/performance based regulation mechanism refers to targeted performance incentive mechanism (Aas, 2016) where emphasis is placed on efficiency improvement and cost reduction (Joskow, 2008). These have been implemented in many monopolised industries as risk/reward mechanisms to incentivised utilities to achieve both economic and non-economic policy outcomes (Aas, 2016).

Performance based regulations give the regulated body the incentives to innovate and drive efficiencies and in return are rewarded with some of the opportunities for upside benefits (Aggarwal and Burgess, 2014; Sirasoontorn, 2008). This involves the use of targeted performance incentives mechanisms to motivate performance against specific outcomes (Aggarwal and Burgess, 2014).

It is important to note that tying the financial health of the utility to outcomes that society cares about can be a very powerful tool to reveal new potential for cost savings and efficiency. The most widely adopted incentive based regulation schemes are; price-cap, revenue-cap, yardstick regulation, targeted-incentive regulation, sliding scale, menu contracts and partial cost adjustments (Joskow, 2008; Jamasd and Pollitt, 2007).

Performance based regulations can work efficiently in a MBM or in a more competitive and restructured system with many third party service providers (Aggarwal and Burgess, 2014) and can be aligned with the transition into a MBM. Utilities are already described as "standard driven" industries, meaning that companies are always driven to meet a minimum requirement or face a penalty performance based regulations which can give companies the benefit of exceeding the minimum requirements.

7.5.0. Price Regulation Principles for the Gas Industry in Ghana

PURC is in the process of developing a tariff setting guideline for the gas industry [Downstream-PURC]. The need for gas price regulation will vary for the different structural models. The SBM requires regulations but transition to MBM requires minimal regulations and prices can be left to the participating parties to negotiate.

In the SBM where gas prices are to be regulated by PURC what will be the composition of the Automatic Tariff Adjustment Formula (ATAF) for gas prices? This should be able to account for the real value of gas through adjustments based on variations in competing fuel prices (LCO and heavy fuels), inflation, and indexation to a hub price and generation mix. Cost recovery for the investors and improvement in efficiency linked to cost reduction for the benefit of consumers including lower cost margins for lower income consumers such as small-scale industries, agro-businesses and lifeline consumers.

7.5.1. Tariff Setting for Different Stages of the Chain

How are natural gas tariffs determined in Ghana? Natural gas tariffs setting present a challenge in the nascent gas industry in Ghana. Current downstream gas prices are considered expensive at US$8.7/MMBtu for domestically produced gas and US$8.6/MMBtu for WAGPCo gas.

Natural gas prices are made up of the following components: commodity price; pipeline tariffs; (gathering tariff, transmission tariff and distribution tariffs; Gas processing tariffs) and; levies, margins and taxes (Ghana Gas Master Plan, 2015). Upstream gas commodity prices determination are discussed above in section (7.3.3), this sections discusses the determinations of tariffs in transmission pipelines, the GPP, infrastructure access charges and final consumer gas prices.

7.5.2. Setting Pipeline and Gas Processing Tariffs

Pipeline and gas processing tariffs are a part of the cost components to final gas prices in Ghana. These services are still provided as a bundled service under SBM. There are two tariffs components of the gas transmission pipeline: fixed (reservation) tariffs and variable tariffs (EIA, 2015). Both GPP and transmission tariffs are determined based on a regulated scheme under PURC.

PURC regulates gas transmission and the gas processing infrastructure tariffs, whilst the WAGP Authority located in Abuja (Nigeria) regulates the WAGP transmission tariffs. PURC do not interfere in the regulation of WAGPCo services and tariffs [Midstream-EC; Midstream-WAGPCo; Downstream-PURC].

The WAGP operates as a natural monopoly, transmitting N-Gas Ltd (Nigeria Gas) gas (the only shipper using WAGPCo services) into Ghana. Natural gas pipeline and processing tariffs are subjected to regulations even in liberalised markets (World Energy Council, 2001). However, regulators are moving towards performance based regulatory mechanism rather than cost based or rate-of-return regulatory mechanisms (Aggarwal and Burgess, 2014).

WAGPCo charges a US$5.03/MMBtu tariff, which reflects full cost recovery and profitability margin plus the N-Gas current commodity price of US$2.5/MMBtu and a WAGP Authority regulatory levy and taxes of US$1.07/MMBtu which adds up to the US$8.6/MMBtu as WAGP gas prices delivered in Ghana [Midstream-WAGPCo].

Why is the WAGPCo tariff charge so high? WAGPCo has been operating for about a decade in Ghana and still charges a transmission tariff of US$5.03/MMBtu. Have WAGPCo not recovered their full/partial capital cost? Why such high regulatory levies and taxes? Transmission pipelines have lower operating cost, so why the higher tariff charge from WAGPCo?

GNPC and GNGC charges a combined transmission tariff and gas-processing tariff of US$5.28/MMBtu [Midstream-GNGC]. What is the basis for combining the GPP and transmission pipeline tariffs? Under the SBM, GNPC provides the processing and transmission services as a bundle, so these are operated as a single company. From the integrated cash flow analysis (see Chapter Six), the GPP and the transmission pipeline are making significant profits at their given tariffs of US$3/MMBtu and US$2.28/MMBtu and there is room for a 50% tariffs reduction to US$1.7/MMBu and US$1.14/MMBtu respectively. These challenges in arriving at appropriate tariffs for the GPP and transmission pipeline calls for designing the best set of regulatory mechanism for natural gas tariff setting in Ghana.

The Tanzania Petroleum Development Corporation (TPDC) set out a process to determine their gas processing and transmission pipeline tariffs. It was considered that, all users irrespective of distance would pay the same tariff. The overall principle in calculating the tariff has been first to determine the cost involved in the construction and operation of the facility with an appropriate return on equity and secondly to determine the volume of the gas demand that the facility can handle on annual basis during the project life.

The European Commission (2015) as well identified four tariff-setting processes for consideration. Allocation of risk between regulated firms and consumers: pipeline and GPP investors must be compensated with higher returns and infrastructure owners should be protected from risk that's out of their control such as volumetric risk and tariffs charge at any given time should reflect this risk (European Commission, 2015);

Benchmarking and standard costing: provides information on efficient tariffs on the cost of new or replacement infrastructure. Availability of sufficient information on the pipeline or GPP can inform the regulators the appropriate rate of return and incentive scheme to introduce (European Commission, 2015).

Balancing optimal investment decisions and trade-off between operating cost and capital cost: this allows the investors to select the optimal investment path and ratio between operating and capital cost and could depart from the CAPEX/OPEX ratio in favour of other lower cost alternatives (European Commission, 2015).

Incentive based mechanisms: are implemented to induce the regulator to reduce operating cost. These are based on standard costing of comparing operating cost from different pipelines or GPPs and predetermination of allowed revenues for a certain number of years, irrespective of the actual operating cost (European Commission, 2015). Natural gas tariffs setting regulations in Ghana can therefore consider balancing rate-of-return and incentive based regulations.

7.5.3. Pipelines and Essential Infrastructure Access Regulations in Ghana

The Energy Commission developed natural gas transmission pipelines access codes that establish a Natural Gas Interconnected Transmission System

(NGITS). The access code governs how a shipper interconnects with the pipelines, terms, and conditions for the provision of transmission services. The access codes are aimed at promoting the development of competitive gas markets by establishing uniform principles for owners and users and allow transparent and non-discriminatory access to the gas transmission system. The access codes aims at preventing abuse of power by the NGTU. There are legislatives instruments that supplement the access code including:

- LI 1911: Natural Gas Distribution and Sales (Technical and operational) Rules, 2007
- LI 1912: Natural Gas Distribution and Sales (Standard of Performance) Regulations 2007
- LI. 1913: Natural Gas Transmission Utility (Technical and operational) Rules, 2007
- LI. 1936: Natural Gas Transmission Utility (Standard of performance) Regulations 2008
- LI. 2189: Natural Gas Pipeline Safety (Construction, Operations and Maintenance) Regulations, 2012.

On the other hand, the WAGP treaty establishes WAGP in fulfilment of the ECOWAS treaty article 28 to promote harmonised hydrocarbon utilisation among member states. WAGP International Project Agreement guided the construction of WAGP. WAGP Authority commences open access regulations on WAGP by issuing two access codes: A and B, which guarantees the provision of transport services on non-discriminatory basis to all shippers.

These are ex ante infrastructure access rules as defined by a third party regulatory body which allows every gas owner/shipper/trader to access the infrastructure (pipelines/FSRU) following a regulated set of procedures and paying a regulated tariff only when there is excess capacity and less safety risk (Hallack and Vazquez, 2013) and these are compatible with the SBM.

However, access tariffs can be negotiated between pipeline owners and shippers and the rules of network use are defined in the contract between the shipper and the pipeline owner and supervised by the independent gas industry regulatory authority (Hallack and Vazquez, 2014). Other users outside the contract can apply to use the pipeline and can be included or excluded based on available capacity and if the exclusion is not justified the independent gas regulatory authority may intervene (Hallack and Vazquez, 2014) and these are compatible when there are multiple gas owners in bilateral asset specific transactions in the MBM. However, no third parties apart from the original owners of both parties attempted using these pipelines, which leaves the rules and regulations untested and difficult to determine their effectiveness.

7.5.4. Final Consumer Gas Tariffs

Downstream natural gas consumption is mostly for power generation and there are opportunities for industrial demand. Natural gas prices in Ghana has been reported to be very expensive by downstream consumers (IPPs) especially when LCO prices are falling. The interviewee at VRA noted that:

> *'Gas prices are very high now, especially with current falling LCO prices. It is not economical to produce electricity from gas because the break-even price is US$85/barrel of LCO to US$8.7/MMBtu of gas. Below US$85/barrel makes producing electricity from gas at US$8.7/MMBtu uneconomical'* [Downstream-VRA].

This interviewee recounted that, because of the asset specificity and the nature of contractual agreements between gas consumers and producers, it would have been more economical to use LCO instead of gas for electricity generation in Ghana at LCO prices below US$50/barrel (Brent crude: US$74.45/barrel) (Bloomberg, 26/04/2018) [Downstream-VRA]. However, two interviewees confirmed that, in the long run and for some of the CCGT plants in the short-term, it is technically, environmentally and economically efficient to rely on gas instead of LCO [Downstream-VRA; TICO-IPP]. The challenge is on how to price downstream gas to reflect alternative CCGT fuels such as LCO.

How can PURC include alternative fuel prices in gas tariff determination? In the SBM, consumer gas prices are regulated and PURC will be responsible for including alternative fuel indexation in gas prices. However, natural gas prices are better set when they reflect market and economic fundamentals (EIA, 2015; Stern and Rogers, 2011) which is the price of gas compared to the price of substitutes and the cost of developing and delivering domestic or imported gas to end-users (Stern and Rogers, 2011).

In the MBM, downstream consumer gas prices will be negotiated between the buyer and seller which would specify the terms of sale including the gas tariff and these are bulk traders, negotiated gas prices can be determine which reflect market fundamentals without much intervention from the independent gas regulatory authority.

7.6.0. Gas Sector Regulatory Governance Arrangements in Ghana

Regulatory governance is aimed at designing a legal regulatory system, institutional arrangements and the process of regulatory decision-making, which includes clarity of roles and responsibilities and demarcation of jurisdictions and functions among regulatory entities (Eberhard, 2007). The World Bank (2013) report recognised poor regulatory governance in the nascent gas industry, which makes it difficult to attract investors. All stakeholders in separate interviews identified:

> '*Lack of clarity of roles and responsibilities and poor demarcation of areas of jurisdiction of players in the natural gas industry in Ghana*' [Stakeholders Consultation].

Sovacool and Jarvis (2011) conceptualised that, regulatory governance arrangements are based on the following assessment criteria: autonomy; clarity of roles and objectives; accountability and transparency; predictability and stability; participation; integrity; credibility and legitimacy. These are used to assess regulatory governance arrangement in the gas industry in Ghana.

Clarity of roles and objectives: there should be separation of regulation from policymaking (Eberhard, 2007). There exist a gas utilisation plan and a gas pricing policy developed by the Ministry of Energy. However, there is no specific gas industry policy for Ghana.

There are overlapping and conflicting roles between the Petroleum Commission and Energy Commission in midstream as to who should regulate the activities of the FSRU. Energy Commission is contesting the role of GNPC as the aggregator as operating without a license. There are conflicting roles between GNGC and BOST on the NGTU licence. There is lack of clarity and conflicting roles and responsibilities between these governmental agencies and as Table 49 indicates. A much clearer policy objective is required for the gas industry involving a link between gas and electricity industries; a gas industry policy framework which clearly demarcates all roles and responsibilities among the various players in the industry from upstream, midstream to downstream.

Table 49: Overlapping Roles in the Natural Gas Industry in Ghana

Organisation	Role	Jurisdiction	Area of Conflict
Petroleum Commission	Upstream regulator of natural gas production fields	Upstream	Who regulates GNPC's role as a gas aggregator?
GNPC	Aggregates upstream gas and LNG importation	Midstream & downstream	Who regulates GNPC gas activities?
Energy Commission	Gas Infrastructure regulator	Upstream & Midstream	Who regulates the activities of LNG importation and the FSRU?
GNGC & BOST	GPP and transmission pipeline infrastructure owner	Midstream	Between GNGC and BOST who should be the NGTU

Source: Data from Interviews.

Regulatory bodies such as Petroleum Commission, Energy Commission and PURC activities need to be properly coordinated to operate as a single unit regulator for the gas industry. An independent gas industry regulatory authority with decision-making and institutional independence is recommended (Eberhard, 2007), which includes:

Autonomy: where the regulatory body can make decisions without referring to another authority and can carry out its mandate and make decisions on its own. This agency will need to operate with autonomy without political interferences (Sovacool, 2011).

Accountability and Transparency: Key concerns for the gas industry is transparency in setting gas prices and tariffs for the transmission pipelines and the GPP and setting tariffs for the upcoming LNG regasification unit and other infrastructure. The regulator should be accountable to all gas industry stakeholders including the parliament, Ghana government, the public, the regulated bodies and consumers.

The regulated body should be able to appeal against the regulators decisions and the possibility of legal redress if the regulator fails to perform their functions (Eberhard, 2007). Transparency requires that the regulator have clearly defined published procedures under which they make and announce decision in setting gas prices and tariffs (Eberhard, 2007).

Predictability and stability: the Ministry of Energy needs to come out with the gas industry policy objective, define the roles and responsibilities of each of the sectors' players and these must be consistent with the national energy policy. These objectives, roles and responsibilities should be predictable and stable for all the industry players. An independent gas regulatory authority can be mandated with regulatory responsibilities of the gas industry to bring stability to the gas industry in Ghana.

Integrity: all the players must ensure that the gas industry is not undermined, impaired or diminished by external factors. This requires personnel and individuals working in the industry committed to the objectives, values and principles of the regulatory and structural system through abiding by ethics and code of conduct. This requires the action of the independent gas regulator to ensure and enforce integrity on all the gas industry agencies. The regulatory system must be credible ensuring that the regulatory body honours their commitments to other players in the gas industry. For example, the setting of gas prices and infrastructure tariffs should involve all stakeholders. They should be some credibility in determining and negotiating upstream wellhead gas prices between GNPC and IOCs.

To improve governance arrangements in the gas industry in Ghana will require creating an independent gas regulatory authority free from the influence of the Ministry of Energy and the private sector. The regulator will be responsible for consolidating all the roles and responsibilities currently held by the various governmental agencies into a single entity. The new gas regulatory authority will then be responsible for the regulation and formulation of policies for the entire gas industry value chain in Ghana.

7.7.0. Natural Gas Industry Policy and Sector Act for Ghana

A solution to all the confusion in gas regulations in Ghana is a sound regulatory governance arrangement and passing a natural gas sector law that will define the powers of the independent regulatory authority to provide infrastructure regulatory framework. Such a law would define the gas industry policy and structure to provide a reliable level playing field for all the participants and thus ensure private investor confidence. It would ensure aggressive consolidation throughout the gas value chain and high cost-efficiency and security of gas supply in Ghana.

The natural gas law will be different from the E&P Bills and general Petroleum sector laws (e.g. Model Petroleum Agreements) and will focus on the gas industry (Leuch, 2012). One interviewee noted the confusion in pricing gas in Ghana and that PURC is arbitrarily setting gas prices.

> *'Some other person might soon find gas and they will also have to give their own price'* [IOC-ENI-Ghana].

Implying that there is no standard regulation or procedure for setting prices of existing and new gas supply sources in Ghana. Each natural gas producer or supply needs to negotiate with PURC for a different gas price. In SBM, natural gas prices are usually regulated and in the MBM prices are negotiated between the producer and the seller. The seller will usually require a price that covers his CAPEX, OPEX, risk and profit margin for shareholders and the buyer which is usually an electricity producer would agree to pay a price that allows a sufficient margin and sufficient profits to their shareholders (natgas.info, 2017). The buyer considers the price of other fuel substitutes in taking this final decision. The negotiated gas pricing approach given the limited number of gas producers in the nascent case proves difficult. A case-by-case pricing approach is convenient, particularly when production costs are significantly different. The negotiated price gives room for price manipulation. In MBM, where there are multiple buyers of gas, negotiated prices are combined with traded prices, which reflects market fundamentals (natgas.info, 2017).

However, the most efficient way of pricing gas is to consider the various supply cost components to arrive at an economic price and a diversified gas supply base means lower gas prices can easily be negotiated (Giziene and Zalgiryte, 2015). With the gas pricing policy there need to be a pricing methodology for the different gas supply sources between different buyers. One interviewee stated that, gas pricing policy and the methodology needs to be legislated into a natural gas law, which should clearly identify the role of the key stakeholders and state the processes on how each source of gas can be priced [IOC-ENI-Ghana]. These gas-pricing methodologies should be able to reflect lower prices for low-income earners and pro-poor tariffs for lower consumers.

In Ghana different institutions regulates the different sectors of the gas industry leading to multiplicity and complexities of roles. There is the possibility of consolidating these rules to a single regulatory authority. A major duty of the authority will be to promote activities along the entire gas supply chain by target actions (Leuch, 2012). The Ministry of Energy is promulgating and developing instruments towards developing the gas law [Upstream-GNPC; Downstream-PURC] through the Gas Master Plan and a final gas law is envisaged for Ghana. To be effective the regulator or the regulatory system needs not to be set-up by only a legislation instrument (Sundar, 2001). Given the fact that, regulation is new to developing countries, it is perhaps best if the independent gas regulatory authority is set up by Ghana’s Act of parliament because setting regulations by only legislation is not enough.

Box 10: Provisions of the Gas Sector Law in Ghana

The gas sector law should set out the natural gas sector policy in relation to the overall energy policy of Ghana. The law should clearly define the gas industry policy, industry structure, regulatory arrangements and infrastructure investment plan and roadmap for the industry development to institutionalise the Gas Master Plan. The law should encourage the development of domestic gas and facilitate national interest in gas imports or exports. The law should focus on addressing peculiarities containing provisions for production/supply, transportation, commercialisation and utilisation in the natural gas industry.

The law needs to define the roles and responsibilities between the different governmental agencies rather than splitting responsibilities arbitrarily (IEA, 2012). Pricing has been a major issue in the natural gas industry in Ghana and there is the need for reviewing the current gas pricing policy to include a pricing methodology for the different sources of gas. The law needs to clarify how gas should be priced in Ghana.

The law needs to define clearly the provision of gas infrastructure. The law should be able to make provisions for longer appraisal and productions periods for domestic gas projects with the right to authorise a specific gas retention license for assessing the viability of a gas discovery and finding off-takers. The law should provide for mandatory joint exploitation of gas discoveries between several licensees when such systems renders gas projects viable and otherwise non-viable and provide principles of constituting a national gas reserves and set conditions for authorising exports or imports.

The law should define governance issues relating to transparency, accountability, integrity in publishing gas prices and tariffs, government revenues and related agreements in oil and gas and make provisions for a sovereign gas fund for revenue savings. The law should consolidate all existing legislative instruments into a single gas sector law. The law should decide whether to create an independent gas regulatory authority or an entity created under any of the governmental agencies responsible for gas regulations. Source: (Leuch, 2012).

7.8.0. Chapter Summary

In conclusion, ineffective regulation was identified as a major challenge in the nascent gas industry in Ghana and this chapter examined the processes involved in providing effective and appropriate regulations and governance arrangements. All the players in the gas industry agreed that, efforts should be made towards designing appropriate regulations. An alternative and independent regulator to the gas industry in Ghana is required to provide effective regulations. Regulatory emphasis is placed on attracting and sustaining infrastructure investments. Finally, a gas industry law is required to consolidate all existing regulations in the nascent gas industry in Ghana.

CHAPTER EIGHT

CONCLUSION

8.0. Conclusion and Recommendations

The study developed an analytical framework, used to examine the three objectives of the study: to evaluate possible gas industry structures, assess the viability of each component of the gas supply chain and, develop suitable regulatory and governance arrangements to support business viability in the nascent gas industry in Ghana. The study agrees with the theoretical review combining SCP and TCE in structure, regulations and infrastructure investment decisions for integrated gas-to-power studies, which allows holistic analysis of the interconnectedness of the nascent gas industry in Ghana.

Natural gas supply has become an important component of ensuring energy security and maintaining macroeconomic stability in Ghana. All the gas supply sources (domestic production, transnational pipeline transmission, and LNG) are needed to meet the increasing CCGT gas demand and penetration to other sectors such as small and large-scale industries in Ghana. Ghana requires a sustainable supply of energy: hydroelectricity generation capacity is exhausted, shifting focus on the dependence of thermal generation. LCO has proven to be more expensive while gas is considered economically, technically and environmentally efficient. However, the development of the gas industry faces structural, regulatory challenges and high risk.

Four structural models: VIM/SBM, MBM: A and B, Open Access and

Unbundling, were considered; none of the structural models will be able to offer a one-size fit solution to the structural problems facing the nascent gas industry in Ghana: encouraging investment upstream and mid-stream; providing cost effective gas supply to consumers, ensuring supply chain viability and managing risks. SBM causes hold-up, non-payment issues but offers the cheapest supply through cross-subsidies and attract investment upstream through long-term credible contracts. MBM: A reduces hold-up issue but non-payment problems remains. Small consumers are likely to get high cost supply and suppliers may become opportunistic – selling gas to high price markets, which may cause supply reliability issues.

MBM: B offers flexibility to suppliers but lack of long-term credible contracts will not allow upstream investments to materialise. Gas prices are likely to go up, particularly for small users. The market balancing issue will appear and the market can become risky. Non-payment by consumers of gas will remain until IPPs and large users can have access to their own markets. MBM: B is considered most appropriate and suitable as a structural model for the nascent gas industry in Ghana compared to SBM, MBM: A, and unbundling.

The business viability analysis of the supply components of the nascent gas industry in Ghana indicates that gas production cost is high and it cannot support any use that is looking for cheap gas. The government could reduce its tax and royalty burden to reduce the cost of gas production to some extent but even then, local gas will be costly. Imported gas is likely to compete with local gas in the future if excess supply becomes a normal feature of the global market.

Transport and processing tariffs are inappropriately set and are adding to the overall supply cost and need to be revised to make gas more affordable. Ghana cannot expect low cost electricity using gas supply – the wholesale electricity purchase tariff cannot be priced less than US$0.09cents/kWh and the bulk power purchasers (VRA and ECG) would have to be prepared to pay at least this price. The gas sector is a risky business and any hold-up at the consumer end will jeopardise the viability of the entire supply chain.

A downstream large-scale gas consumer such as a fertilizer plant is recommended for strategic consideration to prevent downstream consumer concentration risk and market monopsony power abuse of the single consumer (VRA). MBM: B structure will diversify downstream consumers. Maintaining a viable commercial link between the various supply components is recommended for the development of the nascent gas industry in Ghana.

Ineffective regulation was identified as a major challenge to the nascent gas industry in Ghana. All the players in the gas industry agreed that efforts should be made towards designing appropriate regulations for the nascent gas industry in Ghana. An alternative and independent regulator to the gas industry in Ghana is required to provide effective regulations. Moreover, regulatory emphasis is placed on attracting and sustaining infrastructure investments. Finally, a gas industry law is required to consolidate all existing regulations in the nascent gas industry in Ghana. This study contributes to the existing thinking in the nascent gas industry in Ghana in four major areas:

1. Consider passing the Gas Sector Act to recognise the research and consultancy work undertaken by various individuals, international and governmental agencies. This will provide clear policy and comprehensive structural and regulatory framework for the gas industry in Ghana.

2. The study confirms the need to incentivise gas-to-power investments through incentive-based regulations, provide economic incentives, cost recovery, pro-poor initiatives for gas tariffs and consider reviewing current fiscal policies such as reducing royalties on gas to promote domestic gas production. Transport and processing tariffs should be appropriately set and revised to make gas more affordable. The gas pricing policy needs to be specified and commercial agreements established for gas pricing to take into consideration all the sources of gas, pricing methodology and business viability.

3. It is important to consider reforming the electricity sector to respond to the nascent gas industry in Ghana and this will take into consideration VRA and ECG inefficiencies. Gas demand penetration in other sectors of the economy should be encouraged in the agriculture and small-scale industries to reduce consumer monopsony.

4. This study combines empirical and theoretical underpinnings to the study of the nascent gas industry in Ghana. The study will set the pace to lead the ongoing thinking of using theoretical underpinnings to help explain empirical evidence and vice versa. This occurrence will stimulate further research in the field of gas industry development in other Greenfields, serve as a suitable template of combining theory and empirical evidence for other

nascent cases such as Mozambique, Tanzania, and encourage further domestic development and gas utilization resources in Nigerian.

8.1.0. Energy Policy Recommendations

Natural gas supply is now recognised as an important component of the electricity generation system in Ghana. Adequate and reliable natural gas supply is important to meet the increasing energy requirements and sustaining macroeconomic stability. This requires keeping all the gas supply sources in Ghana viable. Delivering economically efficient gas prices and tariffs are important to keeping the gas industry viable and lowering gas prices is important to delivering lower electricity tariffs in Ghana.

It is recommended for the Ghana government to reduce risk in the gas industry. The viability of the gas industry is highly dependent on reducing investment risk in the upstream, midstream and downstream segments of the industry and most importantly solving the inefficiencies in the electricity sector in Ghana. Strategically, developing large-scale gas consumers such as a fertilizer plant and penetration of gas demand in small-scale consumers are relevant to maintaining a functional gas industry in Ghana.

Ghana government should promote the MBM: B, open access to transmission pipelines and other essential facilities and unbundle the SBM to maintain a viable gas industry in Ghana. Incentive/performance based regulation mechanisms to attract infrastructure investment and keeping a viable gas price and tariffs are important to sustaining private capital investment. A gas industry policy will be essential to promote an independent gas regulator, and consolidate the gas industry regulations into a sector law.

8.2.0. Areas for Future Research

The gas industry in Ghana is emerging and recommending for future study is to take each of the gas industry supply value chains (supply/production, processing and transmission, and the power sector) for further research. A detailed economic modelling of the effects of gas on Ghana's economy could be done to see whether the benefits exceed the costs.

Further research is required in the setting of gas pricing methodologies used by PURC and to advice on their efficiency and ability to serve the interest of all stakeholders especially poor consumers. Further studies should be carried out on the impact of LNG importation, interfacing the global LNG market dynamics into the nascent gas industry in Ghana and determine the preparedness of both governmental and private sector participating in the global LNG market.

Producing electricity from an integrated gas framework delivers very expensive electricity tariffs in Ghana; a comparative study should be conducted in an integrated renewable energy project using solar PV technologies to establish the viability of a solar-to-power project in Ghana. Finally, the power sector poses several challenges to the viability of the nascent gas industry: especially the hold-up and lock-in problems of VRA and ECG. Further studies are recommended in power sector reforms in cost-effective tariff setting electricity to reflect cost recovery and margins for the gas industry viability and allow IPPs access to power consumers.

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Appendix 1: Sample of Consent form

Consent form

Issue	Respondent's initial
I have read the information presented in the information letter about the study " Management of the Structure, Regulation and Investment Decisions in the Natural Gas Industry: the case of Ghana."	AoA
I have had the opportunity to ask any questions related to this study, and received satisfactory answers to my questions, and any additional details I wanted.	Ao A
I am also aware that excerpts from the interview may be included in publications to come from this research. Quotations will be kept anonymous.	AoA
I give permission for the interview to be recorded using audio recording equipment. as a representation of my opinion.	A oA
I understand that relevant sections of the data collected during the study may be looked at by individuals from De Montfort University, The government of Ghana, from regulatory authorities in Ghana or from other potential investors, where it is relevant to my taking part in this research. I give permission for these individuals to have access to my responses.	AoA

With full knowledge of all foregoing, I agree to participate in this study.

I agree to being contacted again by the researchers if my responses give rise to interesting findings or cross references.

☑ no

☐ yes

if yes, my preferred method of being contacted is:

☐ telephone ..0203299278..................

☐ email ....andrew.adu@ghanagas.com.gh..

☐ other ....

Participant Name:	Andrew Adu	Consent taken by	Shafic Suleman
Participant Signature:		Signature	
Date	17-05-16	Date	17-05-16

Appendix 2: Introductory Letters for Interviews

Post Office Box SD 40
Stadium Post Office
Accra,Ghana.

Our Ref:................................
Your Ref:...............................

Telephone:+233 (30
Fax:+233 (
E-mail: info@petrol
Website: www.petrol

MINISTRY OF PETROLEUM
REPUBLIC OF GHANA

20th April, 2016

Prof. Subhes C. Bhattaharyya
Professor of Energy Policy and Economics
Institute of Energy and Sustainable Development
Queens Building, Room 2.07
De Montfort University
Leicester.

RE: LETTER IN SUPPORT OF SHAFIC SULEMAN'S RESEARCH ACTIVITY

Please refer to your letter dated 12th May 2015, which was received on 15th April, 2016 on the subject matter above.

The Ministry wishes to inform you of its willingness to assist.

Please contact Tel. No. +233-302- 667107 or +233-240818981.
Email Address. nancy.ayiku1@gmail.com / nancy.botchway@petromi
n.gov.gh.

PROF. T.M. AKABZAA
CHIEF DIRECTOR
For: MINISTER

Appendix 3: Integrated Cash Flow Model

Upstream Natural Gas Production: Module 1				
Input Data			**Discount Rate Calculations**	
1BCF	1,000,000.00	MMBTU	**Discount Rate**	10.00%
Gas Prices (US$/MMBTU)	9.8	$	**Risk Free Rate(Treasury Bills Rate)**	10%
Gas Royalty Rate	7.5%		**Market Risk Premium**	10.00%
Output Data			**Beta**	1
Gas Project NPV (US$)	**673,399,621.34**			

Period	Year	REVENUES Gas Production Annual Production (BCF)	Gas Annual Production (MMBtu)	Gas Revenues Revenues($)	Royalty Gas Royalty Payable ($)	Total Revenues Available ($)
0	2015	0	-	-	-	-
1	2016	0	-	-	-	-
2	2017	0	-	-	-	-
3	2018	58	58,000,000.00	568,400,000.00	42,630,000.00	525,770,000.00
4	2019	68	68,000,000.00	666,400,000.00	49,980,000.00	616,420,000.00
5	2020	68	68,000,000.00	666,400,000.00	49,980,000.00	616,420,000.00
6	2021	68	68,000,000.00	666,400,000.00	49,980,000.00	616,420,000.00
7	2022	68	68,000,000.00	666,400,000.00	49,980,000.00	616,420,000.00
8	2023	68	68,000,000.00	666,400,000.00	49,980,000.00	616,420,000.00
9	2024	68	68,000,000.00	666,400,000.00	49,980,000.00	616,420,000.00
10	2025	68	68,000,000.00	666,400,000.00	49,980,000.00	616,420,000.00
11	2026	68	68,000,000.00	666,400,000.00	49,980,000.00	616,420,000.00
12	2027	68	68,000,000.00	666,400,000.00	49,980,000.00	616,420,000.00
13	2028	68	68,000,000.00	666,400,000.00	49,980,000.00	616,420,000.00
14	2029	68	68,000,000.00	666,400,000.00	49,980,000.00	616,420,000.00
15	2030	68	68,000,000.00	666,400,000.00	49,980,000.00	616,420,000.00
16	2031	59	59,000,000.00	578,200,000.00	43,365,000.00	534,835,000.00
17	2032	52	52,000,000.00	509,600,000.00	38,220,000.00	471,380,000.00
18	2033	47	47,000,000.00	460,600,000.00	34,545,000.00	426,055,000.00
19	2034	39	39,000,000.00	382,200,000.00	28,665,000.00	353,535,000.00
20	2035	9	9,000,000.00	88,200,000.00	6,615,000.00	81,585,000.00
	Totals	1080	1,080,000,000.00	10,584,000,000.00	793,800,000.00	9,790,200,000.00

CAPITAL EXPENDITURE

Facilities Construction Cost ($)				Facilities Renting Cost ($)		Total CAPEX
Exploration Cost ($)	Constant Capex ($)	Surface Rentals ($)	Decommission Cost ($)	FPSO Upfront Cost ($)	FPSO Rents ($)	CAPEX ($)
83,000,000.00	-	8,000,000.00	-	2,000,000.00	-	93,000,000.00
15,000,000.00	-	0	-	13,000,000.00	-	28,000,000.00
176,000,000.00	-	0	-	49,000,000.00	56,000,000.00	281,000,000.00
143,000,000.00	-	0	-	52,000,000.00	115,000,000.00	310,000,000.00
	10,000,000.00	0	-		115,000,000.00	125,000,000.00
	33,000,000.00	0	-		115,000,000.00	148,000,000.00
	20,000,000.00	0	-		115,000,000.00	135,000,000.00
	56,000,000.00	0	-		115,000,000.00	171,000,000.00
	195,000,000.00	0	-		115,000,000.00	310,000,000.00
	446,000,000.00	0	-		115,000,000.00	561,000,000.00
	377,000,000.00	0	-		115,000,000.00	492,000,000.00
	121,000,000.00	0	-		115,000,000.00	236,000,000.00
	-	0	-		115,000,000.00	115,000,000.00
	-	0	-		115,000,000.00	115,000,000.00
	-	0	-		115,000,000.00	115,000,000.00
	-	0	-		115,000,000.00	115,000,000.00
	-	0	-		115,000,000.00	115,000,000.00
	-	0	-		115,000,000.00	115,000,000.00
	158,000,000.00	0	-		121,000,000.00	279,000,000.00
	-	0	-		115,000,000.00	115,000,000.00
	277,000,000.00	0	400,000.00		26,000,000.00	303,400,000.00
417,000,000.00	1,693,000,000.00	8,000,000.00	400,000.00	116,000,000.00	2,043,000,000.00	4,277,400,000.00

OPERATING EXPENDITURE			
Maintenance Cost ($)	FPSO Running Cost ($)	Onshore Facilities ($)	Total OPEX OPEX($)
-	-	-	-
-	-	-	-
-	-	-	-
24,000,000.00	22,000,000.00	2,000,000.00	48,000,000.00
110,000,000.00	99,000,000.00	11,000,000.00	220,000,000.00
119,000,000.00	98,000,000.00	12,000,000.00	229,000,000.00
124,000,000.00	101,000,000.00	11,000,000.00	236,000,000.00
123,000,000.00	101,000,000.00	11,000,000.00	235,000,000.00
104,000,000.00	101,000,000.00	11,000,000.00	216,000,000.00
104,000,000.00	101,000,000.00	11,000,000.00	216,000,000.00
104,000,000.00	101,000,000.00	11,000,000.00	216,000,000.00
104,000,000.00	101,000,000.00	11,000,000.00	216,000,000.00
104,000,000.00	101,000,000.00	11,000,000.00	216,000,000.00
104,000,000.00	101,000,000.00	11,000,000.00	216,000,000.00
104,000,000.00	101,000,000.00	11,000,000.00	216,000,000.00
104,000,000.00	101,000,000.00	11,000,000.00	216,000,000.00
104,000,000.00	101,000,000.00	11,000,000.00	216,000,000.00
104,000,000.00	101,000,000.00	11,000,000.00	216,000,000.00
12,000,000.00	101,000,000.00	11,000,000.00	124,000,000.00
119,000,000.00	101,000,000.00	12,000,000.00	232,000,000.00
109,000,000.00	98,000,000.00	11,000,000.00	218,000,000.00
1,780,000,000.00	1,731,000,000.00	191,000,000.00	3,702,000,000.00

Total Project Cost ($) CAPEX & OPEX ($)	Net Income ($)	Discounted Cash Flow
93,000,000.00	- 93,000,000.00	- 101,000,000.00
28,000,000.00	- 28,000,000.00	$ -25,454,545.45
281,000,000.00	- 281,000,000.00	$ -232,231,404.96
358,000,000.00	167,770,000.00	$ 126,048,084.15
345,000,000.00	271,420,000.00	$ 185,383,512.06
377,000,000.00	239,420,000.00	$ 148,660,983.17
371,000,000.00	245,420,000.00	$ 138,533,191.91
406,000,000.00	210,420,000.00	$ 107,978,731.24
526,000,000.00	90,420,000.00	$ 42,181,597.32
777,000,000.00	- 160,580,000.00	$ -68,101,595.56
708,000,000.00	- 91,580,000.00	$ -35,308,054.45
452,000,000.00	164,420,000.00	$ 57,628,206.95
331,000,000.00	285,420,000.00	$ 90,943,607.99
331,000,000.00	285,420,000.00	$ 82,676,007.26
331,000,000.00	285,420,000.00	$ 75,160,006.60
331,000,000.00	285,420,000.00	$ 68,327,278.73
331,000,000.00	203,835,000.00	$ 44,360,434.89
331,000,000.00	140,380,000.00	$ 27,773,434.62
403,000,000.00	23,055,000.00	$ 4,146,644.40
347,000,000.00	6,535,000.00	$ 1,068,524.72
521,400,000.00	- 439,815,000.00	$ -65,375,697.26
7,979,400,000.00	1,810,800,000.00	$ 673,398,948.34

Natural Gas Processing Plant: Component 2

Input Data			**Discount Rate Calculations**	
1BCF	1,000,000.00	MMBTU	**Discount Rate**	10%
Gas Processing Tariffs	3	$/MMBTU	**Risk Free Rate(Treasury Bills Rate)**	10%
Products (LGP) Selling Price	320	$/MMBTU	**Market Risk Premium**	10%
Methane Gas Volumes	97%		**Beta**	1
Products Volumes(Propane, Butane,Ethane)	3%			
Output Data				
NPV ($)	566,873,319.85	Associated Gas Prices US$9.8/mmbtu		

Period	Year	Natural Gas Processing Annual Production (BCF)	Annual Processing (MMBTU	Transmission Quantities (MMBTU)	Products Quantities (MMBTU)	Natural Gas Processing Revenues ($)
0	2015	0	-	-	-	-
1	2016	0	-	-	-	-
2	2017	0	-	-	-	-
3	2018	58	58,000,000.00	56,260,000.00	1,740,000.00	168,780,000.00
4	2019	68	68,000,000.00	65,960,000.00	2,040,000.00	197,880,000.00
5	2020	68	68,000,000.00	65,960,000.00	2,040,000.00	197,880,000.00
6	2021	68	68,000,000.00	65,960,000.00	2,040,000.00	197,880,000.00
7	2022	68	68,000,000.00	65,960,000.00	2,040,000.00	197,880,000.00
8	2023	68	68,000,000.00	65,960,000.00	2,040,000.00	197,880,000.00
9	2024	68	68,000,000.00	65,960,000.00	2,040,000.00	197,880,000.00
10	2025	68	68,000,000.00	65,960,000.00	2,040,000.00	197,880,000.00
11	2026	68	68,000,000.00	65,960,000.00	2,040,000.00	197,880,000.00
12	2027	68	68,000,000.00	65,960,000.00	2,040,000.00	197,880,000.00
13	2028	68	68,000,000.00	65,960,000.00	2,040,000.00	197,880,000.00
14	2029	68	68,000,000.00	65,960,000.00	2,040,000.00	197,880,000.00
15	2030	68	68,000,000.00	65,960,000.00	2,040,000.00	197,880,000.00
16	2031	59	59,000,000.00	57,230,000.00	1,770,000.00	171,690,000.00
17	2032	52	52,000,000.00	50,440,000.00	1,560,000.00	151,320,000.00
18	2033	47	47,000,000.00	45,590,000.00	1,410,000.00	136,770,000.00
19	2034	39	39,000,000.00	37,830,000.00	1,170,000.00	113,490,000.00
20	2035	9	9,000,000.00	8,730,000.00	270,000.00	26,190,000.00
	TOTALS	1080	1,080,000,000.00	1,047,600,000.00	32,400,000.00	3,142,800,000.00

Products Revenues ($)	Associated Gas Cost	REVENUES Net Revenues ($)		CAPITAL EXPENDITURE CAPEX	OPERATIONS EXPENDITURE Maintenance and Operating Cost
-	-	-		129,333,333.33	-
-	-	-		128,333,333.33	-
-	-	-		128,333,333.33	-
556,800,000.00	568,400,000.00	157,180,000.00			19,300,000.00
652,800,000.00	666,400,000.00	184,280,000.00			19,300,000.00
652,800,000.00	666,400,000.00	184,280,000.00			19,300,000.00
652,800,000.00	666,400,000.00	184,280,000.00			19,300,000.00
652,800,000.00	666,400,000.00	184,280,000.00			19,300,000.00
652,800,000.00	666,400,000.00	184,280,000.00			19,300,000.00
652,800,000.00	666,400,000.00	184,280,000.00			19,300,000.00
652,800,000.00	666,400,000.00	184,280,000.00			19,300,000.00
652,800,000.00	666,400,000.00	184,280,000.00			19,300,000.00
652,800,000.00	666,400,000.00	184,280,000.00			19,300,000.00
652,800,000.00	666,400,000.00	184,280,000.00			19,300,000.00
652,800,000.00	666,400,000.00	184,280,000.00			19,300,000.00
652,800,000.00	666,400,000.00	184,280,000.00			19,300,000.00
566,400,000.00	578,200,000.00	159,890,000.00			19,300,000.00
499,200,000.00	509,600,000.00	140,920,000.00			19,300,000.00
451,200,000.00	460,600,000.00	127,370,000.00			19,300,000.00
374,400,000.00	382,200,000.00	105,690,000.00			19,300,000.00
86,400,000.00	88,200,000.00	24,390,000.00			19,300,000.00
10,368,000,000.00	10,584,000,000.00	2,926,800,000.00		385,999,999.99	347,399,999.99

				CASHFLOWS	
Labour Cost	Total OPEX		Total Project CAPEX & OPEX	Net Income	Discounted Cash Flows
11,000,000.00	11,000,000.00		140,333,333.33	- 140,333,333.33	$ -140,333,333.33
11,000,000.00	11,000,000.00		139,333,333.33	- 139,333,333.33	$ -126,666,666.66
11,000,000.00	11,000,000.00		139,333,333.33	- 139,333,333.33	$ -115,151,515.15
13,000,000.00	32,300,000.00		32,300,000.00	124,880,000.00	$ 93,824,192.34
13,000,000.00	32,300,000.00		32,300,000.00	151,980,000.00	$ 103,804,384.95
13,000,000.00	32,300,000.00		32,300,000.00	151,980,000.00	$ 94,367,622.68
13,000,000.00	32,300,000.00		32,300,000.00	151,980,000.00	$ 85,788,747.89
13,000,000.00	32,300,000.00		32,300,000.00	151,980,000.00	$ 77,989,770.81
13,000,000.00	32,300,000.00		32,300,000.00	151,980,000.00	$ 70,899,791.64
13,000,000.00	32,300,000.00		32,300,000.00	151,980,000.00	$ 64,454,356.04
13,000,000.00	32,300,000.00		32,300,000.00	151,980,000.00	$ 58,594,869.13
13,000,000.00	32,300,000.00		32,300,000.00	151,980,000.00	$ 53,268,062.84
13,000,000.00	32,300,000.00		32,300,000.00	151,980,000.00	$ 48,425,511.68
13,000,000.00	32,300,000.00		32,300,000.00	151,980,000.00	$ 44,023,192.43
13,000,000.00	32,300,000.00		32,300,000.00	151,980,000.00	$ 40,021,084.03
13,000,000.00	32,300,000.00		32,300,000.00	151,980,000.00	$ 36,382,803.66
13,000,000.00	32,300,000.00		32,300,000.00	127,590,000.00	$ 27,767,301.44
13,000,000.00	32,300,000.00		32,300,000.00	108,620,000.00	$ 21,489,887.94
13,000,000.00	32,300,000.00		32,300,000.00	95,070,000.00	$ 17,099,175.16
13,000,000.00	32,300,000.00		32,300,000.00	73,390,000.00	$ 11,999,851.45
13,000,000.00	32,300,000.00		32,300,000.00	- 7,910,000.00	$ -1,175,771.10
267,000,000.00	614,399,999.99		1,000,399,999.98	1,926,400,000.02	$ 566,873,319.85

Transmission Pipeline: Model 3

Input Data			**Discount Rate Calculations**	
1BCF	1,000,000.00	**MMBTU**	**Discount Rate**	10%
Estimated Loss Rate Due to Processing	5.0%		**Risk Free Rate(Treasury Bills Rate)**	10%
Transmission Tariffs	2.28	**($/MMBTU)**	**Market Risk Premium**	10%
	%		**Beta**	1

Output Data	
Transmission Pipeline NPV ($)	552,948,107.41

		TRANSMISSION QUANTITIES			REVENUES
Period	Year	Transmission Quantities (MMBTU)	Processing Losses (MMBTU)	Transmission Pipeline Quantities (MMBTU)	Transmission Revenues ($)
0	2015	-	-	-	-
1	2016	-	-	-	-
2	2017	-	-	-	-
3	2018	56,260,000.00	2,813,000.00	53,447,000.00	121,859,160.00
4	2019	65,960,000.00	3,298,000.00	62,662,000.00	142,869,360.00
5	2020	65,960,000.00	3,298,000.00	62,662,000.00	142,869,360.00
6	2021	65,960,000.00	3,298,000.00	62,662,000.00	142,869,360.00
7	2022	65,960,000.00	3,298,000.00	62,662,000.00	142,869,360.00
8	2023	65,960,000.00	3,298,000.00	62,662,000.00	142,869,360.00
9	2024	65,960,000.00	3,298,000.00	62,662,000.00	142,869,360.00
10	2025	65,960,000.00	3,298,000.00	62,662,000.00	142,869,360.00
11	2026	65,960,000.00	3,298,000.00	62,662,000.00	142,869,360.00
12	2027	65,960,000.00	3,298,000.00	62,662,000.00	142,869,360.00
13	2028	65,960,000.00	3,298,000.00	62,662,000.00	142,869,360.00
14	2029	65,960,000.00	3,298,000.00	62,662,000.00	142,869,360.00
15	2030	65,960,000.00	3,298,000.00	62,662,000.00	142,869,360.00
16	2031	57,230,000.00	2,861,500.00	54,368,500.00	123,960,180.00
17	2032	50,440,000.00	2,522,000.00	47,918,000.00	109,253,040.00
18	2033	45,590,000.00	2,279,500.00	43,310,500.00	98,747,940.00
19	2034	37,830,000.00	1,891,500.00	35,938,500.00	81,939,780.00
20	2035	8,730,000.00	436,500.00	8,293,500.00	18,909,180.00
	TOTALS	1,047,600,000.00	52,380,000.00	995,220,000.00	2,269,101,600.00

CAPITAL EXPENDITURE CAPEX ($)	OPERATIONS EXPENDITURE OPEX ($)	Total Project CAPEX & OPEX Cost ($)	CASHFLOWS Net Income ($)	Discounted Cash Flows ($)
94,000,000.00	-	94,000,000.00	- 94,000,000.00	- 94,000,000.00
94,000,000.00	-	94,000,000.00	- 94,000,000.00	- 85,454,545.45
92,000,000.00	-	92,000,000.00	- 92,000,000.00	- 76,033,057.85
	14,320,000.00	14,320,000.00	107,539,160.00	80,795,762.58
	14,320,000.00	14,320,000.00	128,549,360.00	87,800,942.56
	14,320,000.00	14,320,000.00	128,549,360.00	79,819,038.69
	14,320,000.00	14,320,000.00	128,549,360.00	72,562,762.45
	14,320,000.00	14,320,000.00	128,549,360.00	65,966,147.68
	14,320,000.00	14,320,000.00	128,549,360.00	59,969,225.16
	14,320,000.00	14,320,000.00	128,549,360.00	54,517,477.42
	14,320,000.00	14,320,000.00	128,549,360.00	49,561,343.11
	14,320,000.00	14,320,000.00	128,549,360.00	45,055,766.46
	14,320,000.00	14,320,000.00	128,549,360.00	40,959,787.69
	14,320,000.00	14,320,000.00	128,549,360.00	37,236,170.63
	14,320,000.00	14,320,000.00	128,549,360.00	33,851,064.21
	14,320,000.00	14,320,000.00	128,549,360.00	30,773,694.74
	14,320,000.00	14,320,000.00	109,640,180.00	23,860,897.62
	14,320,000.00	14,320,000.00	94,933,040.00	18,781,995.87
	14,320,000.00	14,320,000.00	84,427,940.00	15,185,107.12
	14,320,000.00	14,320,000.00	67,619,780.00	11,056,374.37
	14,320,000.00	14,320,000.00	4,589,180.00	682,152.36
280,000,000.00	257,760,000.00	537,760,000.00	1,731,341,600.00	552,948,107.41

Combined Cycle Thermal Power Plant: Module 4

Input Data		
Assumptions		Values
Plant Capacity (MW)		1100
Capital Cost ($/kW)		950
Plant Cost ($M)		1045
Plant Life (Years)		20
Plant Load Factor (%)		0.9
Plant Efficiency (%)		0.48
Heat Rate (BTU/kWh)		7120
Operations and Maintenance Costs (OMC)	$21million annual maintenance cost	

Units and Conversions	Values		
Heat Content of Gas (Btu/cu feet)		1030	
1Megawatts	1kW10^3		
Number of Hours/Year		8760	
1 Megawatts		1000	kilowatts
1MMBTU	1,000,000.00		BTU
1BCF		1000	MMcf
		2.087	
		0.48	Plant efficiency
1BCF	1,000,000.00		MMBTU

Annual Electricity Generation (MWh)	8672400	MWh	
Energy required	6.17475E+13	Btu	
Gas Required	59.95	BCF	
Gas Price $/MMBTU	8.7		15.08
Electricity Price cent/kWh ($/kWh)	0.09	What is the contractual off-take price?	
1Megawatthour	1000	kilowatthour	
Output Data			
NPV	388,387,277.18		

Discount Rate Calculations	
Discount Rate	10%
Risk Free Rate(Treasury Bills Rate)	10%
Market Risk Premium	10%
Beta	1

Period	Year	Transmission Pipeline Quantities (MMBTU)	Gas Required (MMBTU) to run 1100 MW plant	Power/Electricity Generated (MWh) with available gas	REVENUES Power/Electricity Sold ($/kWh)
0	2015	-	-	-	-
1	2016	-	-	-	-
2	2017	-	-	-	-
3	2018	53,447,000.00	61,747,488.00	7,506,601.12	675,594,101.12
4	2019	62,662,000.00	61,747,488.00	8,800,842.70	792,075,842.70
5	2020	62,662,000.00	61,747,488.00	8,800,842.70	792,075,842.70
6	2021	62,662,000.00	61,747,488.00	8,800,842.70	792,075,842.70
7	2022	62,662,000.00	61,747,488.00	8,800,842.70	792,075,842.70
8	2023	62,662,000.00	61,747,488.00	8,800,842.70	792,075,842.70
9	2024	62,662,000.00	61,747,488.00	8,800,842.70	792,075,842.70
10	2025	62,662,000.00	61,747,488.00	8,800,842.70	792,075,842.70
11	2026	62,662,000.00	61,747,488.00	8,800,842.70	792,075,842.70
12	2027	62,662,000.00	61,747,488.00	8,800,842.70	792,075,842.70
13	2028	62,662,000.00	61,747,488.00	8,800,842.70	792,075,842.70
14	2029	62,662,000.00	61,747,488.00	8,800,842.70	792,075,842.70
15	2030	62,662,000.00	61,747,488.00	8,800,842.70	792,075,842.70
16	2031	54,368,500.00	61,747,488.00	7,636,025.28	687,242,275.28
17	2032	47,918,000.00	61,747,488.00	6,730,056.18	605,705,056.18
18	2033	43,310,500.00	61,747,488.00	6,082,935.39	547,464,185.39
19	2034	35,938,500.00	61,747,488.00	5,047,542.13	454,278,792.13
20	2035	8,293,500.00	61,747,488.00	1,164,817.42	104,833,567.42
	TOTALS	995,220,000.00	1,111,454,784.00	139,778,089.89	12,580,028,089.89

CAPITAL EXPENDITURE			OPERATIONS EXPENDITURE		
CAPEX	Fuel Cost	Total CAPEX	Maintenance Cost	Labour Cost	Total OPEX
348,333,333.33	-	348,333,333.33	-	-	-
348,333,333.33	-	348,333,333.33	-	-	-
348,333,333.33	-	348,333,333.33	-	-	-
	464,988,900.00	464,988,900.00	21,000,000.00	12,000,000.00	33,000,000.00
	545,159,400.00	545,159,400.00	21,000,000.00	12,000,000.00	33,000,000.00
	545,159,400.00	545,159,400.00	21,000,000.00	12,000,000.00	33,000,000.00
	545,159,400.00	545,159,400.00	21,000,000.00	12,000,000.00	33,000,000.00
	545,159,400.00	545,159,400.00	21,000,000.00	12,000,000.00	33,000,000.00
	545,159,400.00	545,159,400.00	21,000,000.00	12,000,000.00	33,000,000.00
	545,159,400.00	545,159,400.00	21,000,000.00	12,000,000.00	33,000,000.00
	545,159,400.00	545,159,400.00	21,000,000.00	12,000,000.00	33,000,000.00
	545,159,400.00	545,159,400.00	21,000,000.00	12,000,000.00	33,000,000.00
	545,159,400.00	545,159,400.00	21,000,000.00	12,000,000.00	33,000,000.00
	545,159,400.00	545,159,400.00	21,000,000.00	12,000,000.00	33,000,000.00
	545,159,400.00	545,159,400.00	21,000,000.00	12,000,000.00	33,000,000.00
	545,159,400.00	545,159,400.00	21,000,000.00	12,000,000.00	33,000,000.00
	473,005,950.00	473,005,950.00	21,000,000.00	12,000,000.00	33,000,000.00
	416,886,600.00	416,886,600.00	21,000,000.00	12,000,000.00	33,000,000.00
	376,801,350.00	376,801,350.00	21,000,000.00	12,000,000.00	33,000,000.00
	312,664,950.00	312,664,950.00	21,000,000.00	12,000,000.00	33,000,000.00
	72,153,450.00	72,153,450.00	21,000,000.00	12,000,000.00	33,000,000.00
1,045,000,000.00	8,658,414,000.00	9,703,414,000.00	378,000,000.00	216,000,000.00	594,000,000.00

Total Project Cost	CASHFLOWS Net Income	Discounted Cash Flow
348,333,333.33	- 348,333,333.33	- 348,333,333.33
348,333,333.33	- 348,333,333.33	- 316,666,666.67
348,333,333.33	- 348,333,333.33	- 287,878,787.88
497,988,900.00	177,605,201.12	133,437,416.32
578,159,400.00	213,916,442.70	146,107,808.69
578,159,400.00	213,916,442.70	132,825,280.62
578,159,400.00	213,916,442.70	120,750,255.11
578,159,400.00	213,916,442.70	109,772,959.19
578,159,400.00	213,916,442.70	99,793,599.27
578,159,400.00	213,916,442.70	90,721,453.88
578,159,400.00	213,916,442.70	82,474,048.98
578,159,400.00	213,916,442.70	74,976,408.16
578,159,400.00	213,916,442.70	68,160,371.06
578,159,400.00	213,916,442.70	61,963,973.69
578,159,400.00	213,916,442.70	56,330,885.17
578,159,400.00	213,916,442.70	51,209,895.61
506,005,950.00	181,236,325.28	39,442,304.84
449,886,600.00	155,818,456.18	30,827,850.87
409,801,350.00	137,662,835.39	24,759,870.99
345,664,950.00	108,613,842.13	17,759,231.10
105,153,450.00	- 319,882.58	- 47,548.51
10,297,414,000.00	2,282,614,089.89	388,387,277.18